HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

DSS FILE NO. 23SQ.23440-4-9092

PREPARED FOR

DEPARTMENT OF SUPPLY AND SERVICES, CANADA

SUBMITTED BY

ASSOCIATED MINING CONSULTANTS LTD
WITH
NOWSCO WELL SERVICE LTD
AND
GEOTECHNICAL RESOURCES LTD.

PERMIT TO PRACTICE
ASSOCIATED MINING CONSULTANTS LTD.
Signature
Date 24 May 1985
PERMIT NUMBER: P 2361
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

OCT 23 1985
MICROMEDIA

MAY 1985

AR-92

AMCL

A DETAILED REVIEW AND EVALUATION OF HYDROFRACTURING TECHNIQUES FOR THE PREVENTION OF ROCK/GAS OUTBURSTS IN UNDERGROUND CANADIAN COAL MINES

FINAL REPORT

BY

ASSOCIATED MINING CONSULTANTS LTD

WITH

NOWSCO WELL SERVICE LTD

AND

GEOTECHNICAL RESOURCES LTD

WORK ON THIS PROJECT WAS CONDUCTED UNDER THE AUSPICES OF THE CANADA CENTRE FOR MINERAL AND ENERGY TECHNOLOGY, ENERGY, MINES AND RESOURCES, CANADA

DSS FILE NO: 23SQ.23440-4-9092
DSS CONTRACT SERIAL NO: OSQ84-00244
CANMET SCIENTIFIC AUTHORITY: DR. T.R.C. ASTON

167 pp

AMCL

Associated
Mining Consultants Ltd.

6th Floor, 926 - 5 Avenue S.W., Calgary, Alberta T2P 0N7
Tel: (403) 264-9496 Telex: 03 821201

May 24, 1985

FILE: 0203-PB49
REF: AR-92

Cape Breton Coal Research Laboratory
CANMET, Energy, Mines and Resources
210 George Street
SYDNEY, Nova Scotia
B1P 1J3

Attention: Dr. T. Aston
Scientific Authority

Dear Sirs:

Re: Review and Evaluation of Hydrofracturing for Prevention of Rock/Gas Outbursts
DSS File No. 23SQ.23440-4-9092
Contract Serial No. OSQ84-00244

We take pleasure in submitting our final report on Hydrofracturing for the Prevention of Outbursts.

We would like to thank CANMET for sponsoring this study, and for the advice and guidance during its execution.

Respectfully submitted,

ASSOCIATED MINING CONSULTANTS LTD.

Hans U. Bielenstein, P.Geol.
Project Manager

HUB:ms

PROFESSIONAL GEOLOGIST HANS U. BIELENSTEIN ALBERTA

AR-92

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

Table of Contents

	Executive Summary
SECTION 1	Introduction
SECTION 2	Hydrofracturing Concepts
SECTION 3	Current Applications
SECTION 4	Outburst Control Potential
SECTION 5	Demonstration Program for Hydrofracturing Underground
SECTION 6	Research and Development Needs for Demonstration
SECTION 7	Bibliography
APPENDIX A	Equations for Fracture Width at Wellbore
APPENDIX B	Petroleum Case History 1
APPENDIX C	Petroleum Case History 2
APPENDIX D	Petroleum Case History 3
APPENDIX E	Summary of Coalbed Stimulation Treatments

EXECUTIVE SUMMARY

Outbursts of gas and rock from the roof of No.26 Colliery in the Sydney Coalfield first occurred at a depth of about 700 m. The severity of the outbursts increased as the depth of mining increased. Since high pore pressure was thought to be a major factor causing these particular outbursts, hydraulic fracturing was to be investigated. This technique is a commonly used method for stimulating production from oil or gas reservoirs. Well defined rock units (sandstones or coal seams) have been the target for routine hydraulic fracturing.

The mines of the Sydney Coalfield pose a quite different problem, since the sandstones, which are the gas reservoirs, are confined to channel deposits in the proximity of the coal seam roof. The first problem, therefore, is to locate these sandstones ahead of mining.

Computer models have been developed to simulate fracture propagation and post treatment fluid production. The Nowsco FRAC SURE Simulator was used to test the effect of hydraulic fracturing on the channel sandstones. Actual reservoir data was minimal and a range of values was evaluated. The results show that the pore pressure can be reduced significantly over a realistic time period in relation to mine advance.

The research and development work required to demonstrate this technology in the Cape Breton mines is minimal. The basic hardware for drilling directional holes, blending and pumping fracturing fluid, and controlling methane flows is available. Some adaptation will be required to fit permissible motors. The major requirement will be to define the gas reservoir mainly in terms of geometry, state of stress, strength, pore pressure, porosity, permeability and water saturation. This information can be used to properly design the hydraulic fracturing treatment.

AMCL

SOMMAIRE

Des explosions de gaz et de roches à partir du toit de la mine de charbon 'No.26 Colliery' dans le champ de charbon de Sydney se sont d'abord produites à une profondeur d'à peu près 700 m. Les explosions sont devenues plus fortes à mesure que la profondeur de la mine s'est accrue. Comme il a été supposé qu'une pression interstitielle pouvait être un important facteur à l'origine de ces explosions, des recherches sur la fracturation hydraulique ont été faites. Cette technique est communément employée pour stimuler la production des roches-réservoirs de gaz et de pétrole. Des formations de roches bien définies (grès ou couches de charbon) ont été habituellement l'objet de la fracturation hydraulique.

Les mines du champ de charbon de Sydney présentent un problème entièrement différent, puisque le grès, qui est la roche-réservoir de gaz, est restreint à des alluvions sédimentaires dans un chenal, à proximité de la couche du toit. Un premier problème est donc de localiser le grès, et cela avant le début des travaux miniers.

Des modèles informatisés ont été développés afin de simuler la propagation des fractures et la production de fluide associée à ces fractures. Le modèle 'Nowsco FRAC SURE' a été utilisé pour expérimenter l'effet de la fracturation hydraulique sur le chenal de grès. Les données concrètes concernant les roches-réservoirs se sont avérées minimes et une variété de valeurs ont été estimées. Les résultats démontrent que la pression interstitielle peut être sensiblement réduite au cours d'une période de temps réaliste par rapport au développement de la mine.

Les travaux de recherche et de développement nécessaires à la démonstration de cette technique dans les mines du Cap Breton sont minimes. L'équipement de base pour le forage des trous directionnels, le mélange et le

AECL

pompage du fluide de fracturation, et le contrôle du débit de méthane est disponible. Quelques adaptations seront nécessaires pour assembler des moteurs possédant les spécifications requises. La tâche la plus importante sera d'identifier les roches-réservoirs principalement en ce qui concerne leur géomètre, leur état de tension, leur résistance, leur pression interstitielle, leur porosité, leur perméabilité et leur saturation d'eau. Cette information servira à bien concevoir le procédé de fracturation hydraulique.

AR-92

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION 1 - INTRODUCTION

Table of Contents

		Page
1.1	General	1-1
1.2	Canadian Requirements	1-2
1.3	Terms of Reference	1-2
1.4	Project Team	1-3

AMCL

SECTION 1 - INTRODUCTION

1.1 GENERAL

Hydrofracturing is a technique routinely used in the Petroleum Industry to stimulate production from oil or gas reservoirs. During the last decade, pre-mining methane drainage of coal seams, mainly from the surface, has been developed in the USA. This will reduce future ventilation problems and provides methane for sale. As this study progressed, it became quite obvious that hydrofracturing is not a commonly used technique to overcome gas outburst problems. The comprehensive literature review produced reference to gas/coal outbursts only, and none for gas/rock outbursts.

This study deals predominantly with the gas/rock outburst potential of the deep mining off Cape Breton Island, since this is the predominant area for underground coal mining in Canada.

The experience of mining in No.26 Colliery has suggested that there will be a critical depth below which mining-induced, unpredictable outbursts are likely to occur. Hydrofracturing may prevent the occurrence of such outbursts. However, alternative actions that could be considered to reduce the risk of uncontrolled outbursts are:

- The method of mining - size of opening - equipment used.
- The sequencing of operations within different mining methods.
- Controlled shock blasting.
- Pre-cutting/wedge blasting in rock.
- Water ampule cushion blasting.

During any hydrofracturing demonstration, all physical phenomenon should be observed and recorded.

1.2 CANADIAN REQUIREMENTS

Outbursts in Canadian coal mines can be differentiated into gas/coal and gas/rock outbursts. Gas/coal outbursts occurred in numerous mines in the Crowsnest Pass area prior to 1960 and in the Canmore area in the late '60's and early '70's. Gas/rock outbursts have only been reported from the Sydney Coalfield, particularly the now closed No.26 Colliery.

Underground mining in Western Canada has been decreasing. The main application for hydraulic fractures, therefore, is to improve mine safety at depth in the Sydney Coalfield. Lingan (Harbour) Mine, for example, will reach the critical depth in about two years.

A secondary application of hydrofracturing in Eastern Canada could be methane extraction for commercial use. This is being considered by a Canadian company.

1.3 TERMS OF REFERENCE

The terms of reference for this report are:

- Summarize the concepts of hydrofracturing.
- Identify, review and evaluate available hydrofracturing technology for application to de-gassing and de-stressing coal and/or coal measure strata from within an underground coal mine.
- Propose a program of research and development that would lead to the demonstration of hydrofracturing techniques for coal and coal measure strata.
- Identify current and future needs for hydrofracturing in Canadian underground coal mines.

1.4 PROJECT TEAM

This study was carried out under the direction of Hans U. Bielenstein, Project Manager, with Brian W. Saul, J.H. Hall Chamberlin and Pat L. Wright, all of AMCL; Hal Anderson and Jeff Latos of Nowsco Well Service Ltd.; and Arfon H. Jones and Brian Mitchell of Geotechnical Resources Ltd.

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION 2 - HYDROFRACTURING CONCEPTS

Table of Contents

		Page
2.1	**Introduction**	2-1
2.2	**Rock Mechanics**	2-2
2.2.1	Fracture Direction	2-2
2.2.2	Fracture Geometry	2-3
2.2.3	Fracture Containment	2-4
2.3	**Reservoir Properties**	2-7
2.4	**Treatment Parameters**	2-8
2.4.1	Fracturing Fluids	2-8
2.4.2	Injection Rates	2-8
2.4.3	Proppants	2-8
2.5	**Discussion**	2-9

FIGURES
(Following Text)

2-1 **Fracture Orientation for Stress Field**

2-2 **Geometry of the Half Fracture No Slippage at the Boundary**

2-3 **Geometry of the Half Fracture Slippage at the Boundary**

2-4 **Section of a Radially Propagating Fracture**

2-5 **Fracture Formation**

2-6 **In Situ Stresses Higher in Bounding Strata**

2-7 **Three-Dimensional Perspective of the Fracture Originating in GT-2**

AMCL

SECTION 2 - HYDROFRACTURING CONCEPTS

2.1 INTRODUCTION

Hydraulic fracturing is a technique used to extend the formation fluid gathering capability of a drillhole, beyond its immediate vicinity. This technique involves the splitting of rock with pressure transmitted through an hydraulic fluid. A fracture is initiated when the pressure becomes large enough to overcome both the in situ stress and the tensile strength of the rock. Normally the pressure to extend the fracture is less than that required to create it since stress concentrations occur around the wellbore; this pressure must be maintained to extend the fracture by injecting fluid into the fracture.

Hydraulic fracturing is usually applied to an oil or gas bearing formation which has porosity and permeability; because the pressure within the fracture is higher than the internal pore pressure of the rock, fluid will leak from the fracture into the formation. When pumping is stopped, the fluid leaks off and the fracture closes; the rate of leak-off depends on the reservoir properties and the fracturing fluid. A proppant (usually sand) is pumped along with the fluid to keep the fracture from completely closing. The resulting fracture permeability is much larger than the formation permeability and oil or gas can be produced at higher rates than would otherwise be possible.

Many advances have been made to more fully understand hydraulic fractures and how they affect reservoir drainage. These advances are applicable to the fracture design for the Sydney Coalfield. Prior knowledge of the induced fracture is needed to evaluate the effectiveness of degassing outburst prone strata.

AMCL

2.2 ROCK MECHANICS

2.2.1 Fracture Direction

The state of stress within the earth's crust can be resolved into three principle stresses. In a non-tectonic environment these stresses could be assumed to be equal to each other and of a magnitude equal to overburden pressure. Hubbert and Willis (1957) indicated that this is seldom the case as demonstrated by tectonic belts of the earth's crust. They also postulated that if fluid pressure were applied locally within a rockmass and if the pressure was increased to the point of failure, dilation should occur in the direction of the least stress (Figure 2-1). This agrees well with others who have investigated hydraulic fracture orientation.

Daneshy (1971, 1973) investigated fracture initiation at the wellbore. Laboratory model tests revealed that fractures extend in a direction perpendicular to the least principal stress, away from the zone of stress concentration at the wellbore. Abou-Sayed et al. (1978) analyzed fracture extensions in an elastic, homogeneous material; they concluded that a sufficiently long open crack tends to extend in a direction which is more nearly perpendicular to the direction of minimum stress than in the direction of an initial existing crack. This prediction is consistent with laboratory results (Daneshy 1971 and 1973) and field tests (Warpinski et al. 1980).

The disturbance at the surface caused by a fracture can be used to determine the nature of that fracture. Analysis of surface tiltmeter arrays (resolution of 5×10^{-9} radians) surrounding the stimulated well, has been used to determine fracture direction. This has been in excellent agreement with fracture azimuth

verified by coring in a shallow well experiment (Smith et al., 1980). These positive results have been confirmed in several successful tests. It may be possible to use tiltmeters to determine fracture direction in the Sydney Coalfield.

2.2.2 Fracture Geometry

Fracture geometry is a description of the shape of an hydraulically induced fracture. The geometry is dependent on:

- the pressure distribution along the fracture length
- the shear modulus of the formation
- slippage at the bounding formation interfaces.

When vertical fractures are created, two theories regarding geometry exist: one assumes that slip does not occur at bounding formations (Perkins and Kern, 1961), the other assumes that it does (Geertsma and deKlerk, 1969).

If no slippage occurs at the boundaries, the resulting fracture shape is elliptical (Figure 2-2). If slip does occur, the fracture is rectangular (Figure 2-3). Equations describing the width at the wellbore for both situations are given in Appendix A.

The factors that can be controlled to change the width and length for either situation are fluid pump rate and viscosity. Changes in either factor effect the pressure distribution along with the fracture length. As each is increased, fractures tend to become wider and shorter.

Bounding formations are not encountered if a horizontal fracture is created. The resulting fracture shape is parabolic, except for a narrow zone at the tip (Figure 2-4). The geometries derived by

Geertsma and deKlerk (1969), and Perkins and Kern (1961) are quite comparable. Equations describing the width of horizontal fractures are given in Appendix A.

It should be noted that horizontal fractures seldom occur. At shallow depths, where the fracturing pressure is near or in excess of lithostatic pressure, it is difficult to use pressure to determine whether the fracture is horizontal; under these conditions the tensile strength of the rockmass accounts for a greater percentage of the fracturing pressure. In wells that have been logged after fracturing, a horizontal fracture has seldom been documented.

2.2.3 Fracture Containment

An hydraulic fracture will extend in both the vertical and horizontal direction unless some mechanism stops growth. Simonson et al. (1976) listed three factors controlling vertical growth:

- material properties contrast between the reservoir formation and bounding strata
- in situ stress contrast between the reservoir formation and bounding strata
- in situ stress gradients in massive formations that effectively have no barriers.

Contrasts in elastic moduli, between the reservoir formation and the bounding strata, have been investigated as a possible factor controlling vertical fracture growth. Cook and Erdogan (1972) used the elastic moduli in characterizing the load sensed at the crack tip through a mathematical quantity called the stress intensity factor. They calculated values for this factor for a two-dimensional crack approaching an interface between materials

with different elastic moduli. They found that the stress intensity factor approached zero as the fracture propagated towards a higher modulus formation and that it increased as it propagated towards a lower, modulus formation.

Simonson et al. (1978) and Rogers et al. (1977) showed that propagation would stop as the stress intensity factor approached zero and that it would continue if the factor was high. Since the factor went to zero as the crack approached a higher modulus formation, these formations were considered to have the potential of being barriers (Figure 2-5).

Cleary (1978) has since shown that the dimensions of the crack-tip process zone prevents full development of a low stress intensity factor as it approaches the higher modulus formation. That is, the higher modulus formation will not be as good a barrier as originally anticipated. This is supported by field and laboratory observations (Warpinski et al., 1980; Hanson et al., 1980). Cleary (1978) did conclude, however, that although higher moduli formations would not be perfect barriers, they would present the greatest resistance to continued fracture growth. Veatch (1980) reports 'effective' fracture containment for barriers with a moduli factor of three higher than the pay formation.

Simonson et al. (1976) predicted that in situ stress contrast would inhibit fracture growth; this has been borne out by field and laboratory observations (Warpinski et al., 1980). Higher in situ stress can be very effective in preventing fracture growth (Figure 2-6).

Field evidence of the in situ stress influence was presented by Abou-Sayed et al. (1977). In analyzing the shape of the hydraulic fracture in massive granite at the Fenton Hill geothermal site

(Figure 2-7), Abou-Sayed et al. (1977) successfully predicted fracture growth and final configuration. This prediction was based on the in situ stress and fracture fluid pressure gradients.

The onset of slippage between the payzone and the barrier can provide fracture containment as observed in fracturing coal. Under these circumstances, a shear-like cracking occurs along the boundary (Figure 2-5). The fracture may reinitiate, however unless the frictional grip across the interface is too weak or the barrier formation too elastically compliant (Hanson et al., 1980; Veatch, 1980). Laboratory (Hanson et al., 1980) and in-mine (Lambert et al., 1980a) observations provide ample evidence of fracture containment when slippage occurs at the boundaries. Slippage is especially noticeable where a soft, thin shale layer exists at the coal roof.

Macdonald and Caswell (1983) showed that injection rate has an effect on fracture growth. Increased rates increase the fracture width and the resulting stress on the barrier formation. Perkins and Kern (1961) and Geertsma and deKlerk (1969) have shown that width is affected by not only rate but by fracture fluid viscosity and fracture length as well. These factors will also affect containment. In field tests on the Medicine Hat Formation in Southern Alberta, lower pumping rates (3.2 m^3/min reduced from 8.0 m^3/min) reduced fracture heights by up to 50%.

Nolte and Smith (1979) and Nolte (1979) made a significant development to interpreting downhole pressure records of the fracture treatment. Based on the data interpretation, assuming that slip does not occur at the boundaries, they were able to assess the phase during which the fracture was confined within the payzone and to quantify the pressure readings which lead to sand screen-out and height growth.

2.3 RESERVOIR PROPERTIES

Reservoir properties are used to describe the quantity of fluid in the formation and the ability of fluid to flow through the formation. They affect the rate at which fracturing fluid leaks off into the formation and, therefore, influence the fracture treatment.

Darcy's Law relates reservoir properties to flow rates. This equation is listed in Appendix A.

The reservoir properties that are of concern for fracture design are:

- **Porosity** - the pore space of the reservoir rock. Although the porosity does not have an effect on flow, it effects the amount of oil or gas in place in the reservoir.
- **Permeability** - a measure of the ease with which fluid can move through the formation. Both the rate of leak-off during the fracture treatment and production before or after the fracture treatment increase with increased values of permeability.
- **Water Saturation** - the percentage of pore space occupied by water. Changes in water saturation change the relative permeability of the reservoir. As the water saturation increases, the relative permeability of the oil or gas decreases.
- **Internal Pore Pressure** (also reservoir or formation pressure) - the pressure within the pore space of the rock. Fluid flows only where a pressure differential exists. The magnitude of the internal pore pressure affects the pressure differential between the fluid in the fracture and the fluid in the reservoir. This, in turn, affects both leak-off and production. Higher internal pore pressures retard leak-off and increase production. Also, in both oil and gas formations, the internal pore pressure affects the amount of gas in place.
- **Reservoir Fluid Viscosity** - the viscosity of the fluid occupying the pore space. A high viscosity fluid will not flow through the reservoir as easily as a lower viscosity fluid. Leak-off rates will be reduced as the reservoir fluid viscosity goes up, since the fluid leaking from the fracture must displace the fluid in the reservoir. Production will also be less than otherwise possible, since a more viscous fluid will not flow out of the reservoir as easily as a less viscous one.

2.4 TREATMENT PARAMETERS

2.4.1 Fracturing Fluids

Commercial fracturing fluids have undergone significant developments since Napalm gel was introduced in 1949. The basic fracturing fluids have gone through a transition from the Napalm type gels to crude oils, condensates and then to water-based fluids by the late 1960's. Further developments have occurred since that time (Ely, 1981) with the introduction of high viscosity cross-linked and foamed fluids. These fluids exhibit increased proppant carrying capacity and reduced leak-off. With higher proppant loadings there is better potential for the proppant to be trapped across the productive interval.

2.4.2 Injection Rates

Injection rates affect the fracture treatment in three ways:

- **Leak-off** With high injection rates the overall volume of fluid, lost to the formation while pumping, is reduced, because less time is available for leak-off.
- **Containment** Higher injection rates have been shown to increase fracture heights (Macdonald and Caswell, 1983).
- **Geometry** High injection rates will produce fractures that are wider and shorter. This is a result of the frictional pressure drop along the fracture.

2.4.3 Proppants

Proppants are transported by the fluid into the fracture during treatment. On completion of the job they remain in the fracture to hold it open and provide a high conductivity path to the

borehole. Silica sand has been the most commonly used proppant in hydraulic fracturing with 20/40 mesh being the dominant size.

Several proppants have recently been developed to withstand the increased stress of deeper wells. The most successful of these high strength proppants have been sintered bauxite (Cooke et al., 1977), Zirconium Oxide (Sarda, 1978 and 1981) and resin coated sand (Sinclair and Graham, 1978). New lightweight proppants are being developed (Cutler et al, 1981). These lighter proppants will provide greater flexibility in designing and implementing the stimulation treatment.

2.5 DISCUSSION

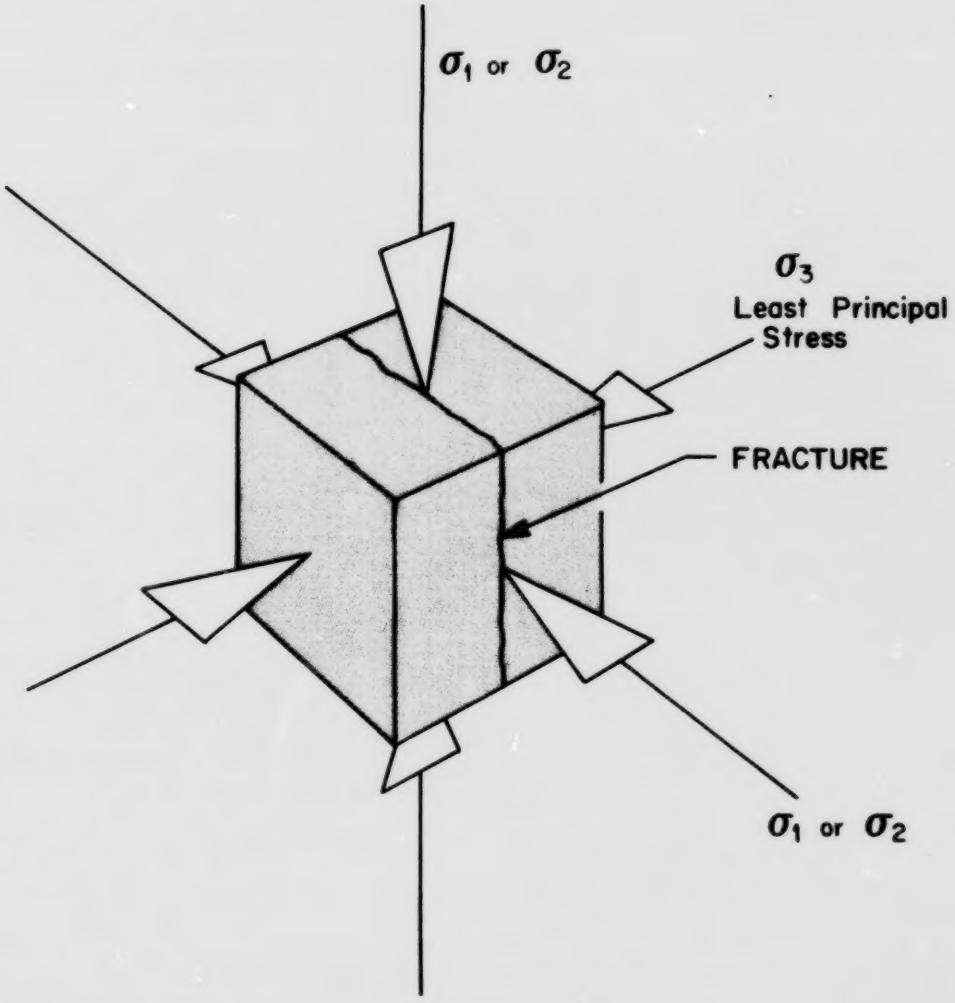
Hydraulic fracturing technology has made many advances since its inception in 1947. It has developed to the point of being the most effective form of well stimulation in the petroleum industry and is carried out on a routine basis.

Significant technological advances have been made in understanding fracture geometry, direction, and containment and how they are affected by in situ stress, rock properties, reservoir properties and treatment parameters. This knowledge will be very helpful in designing fracture treatments for the Sydney coalfield where low permeability and porosity sandstone channels are situated above the coal seams.

FIGURE 2-1

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

FRACTURE ORIENTATION FOR STRESS FIELD

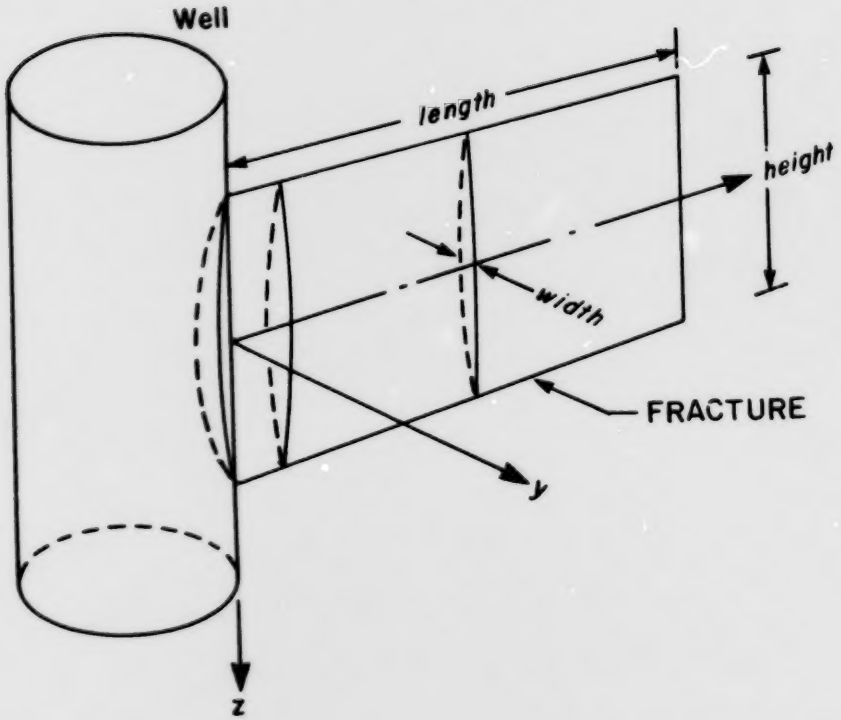


After: Hubbert and Willis (1957)

FIGURE 2-2

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

GEOMETRY OF THE HALF FRACTURE
NO SLIPPAGE AT THE BOUNDARY

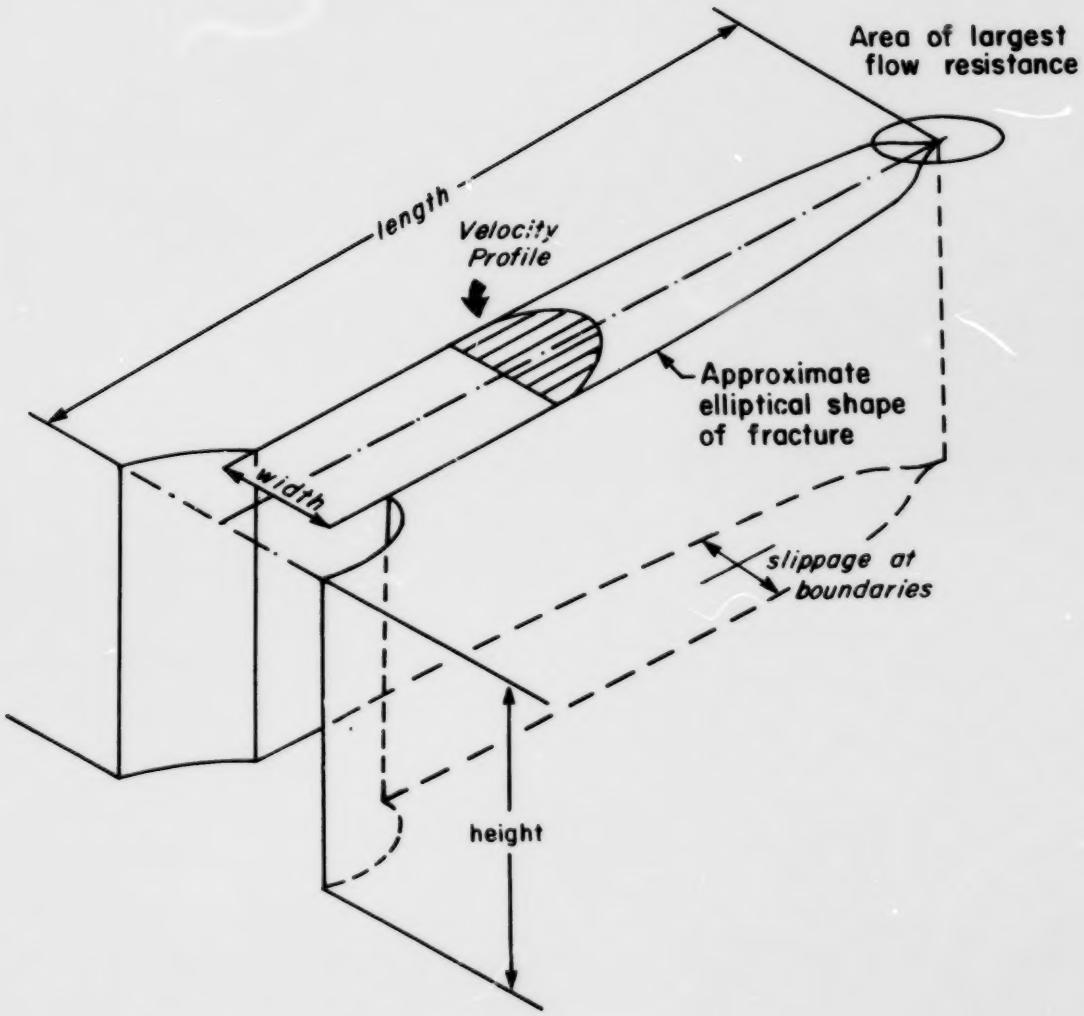


After: Nordgren (1972)

FIGURE 2-3

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

GEOMETRY OF THE HALF FRACTURE SLIPPAGE AT THE BOUNDARY

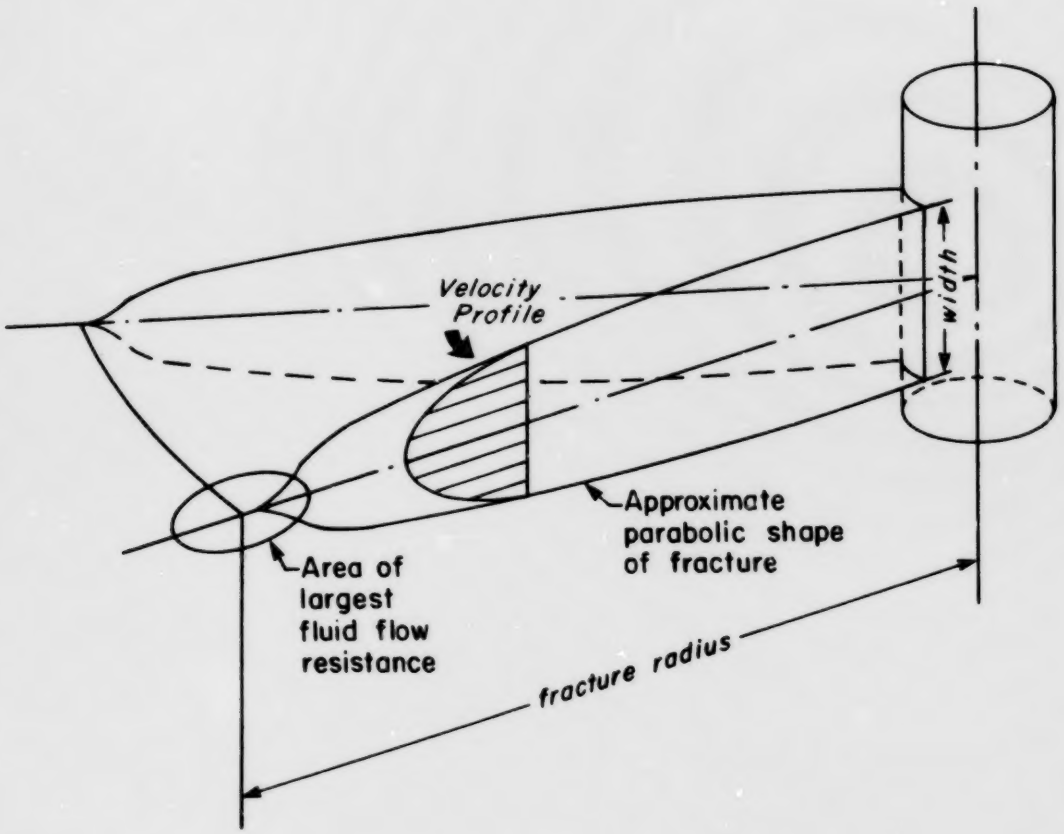


After: Geertsma and de Klerk (1969)

FIGURE 2-4

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION OF A RADIALLY PROPAGATING FRACTURE

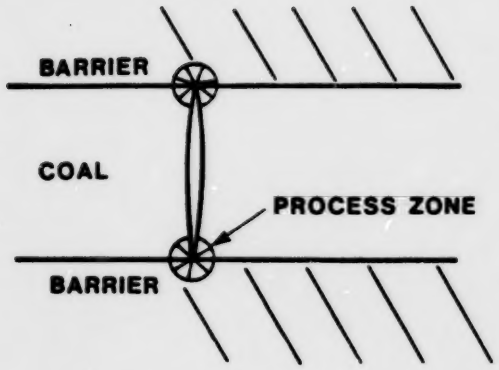


After: Geertsma and de Klerk (1969)

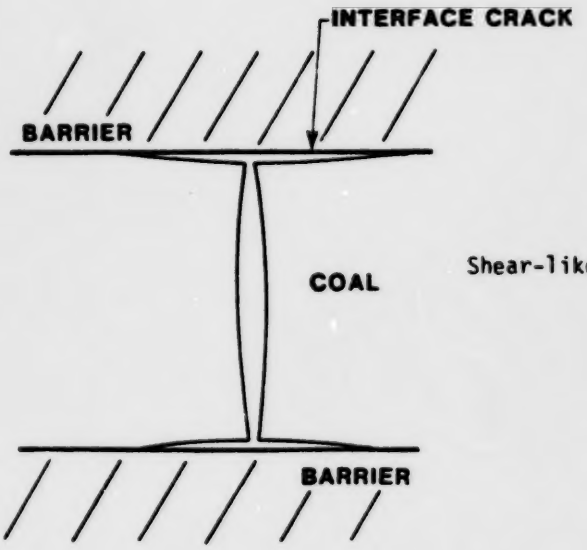
AMCL

FIGURE 2-5
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

FRACTURE FORMATION



Uncontained Fracture

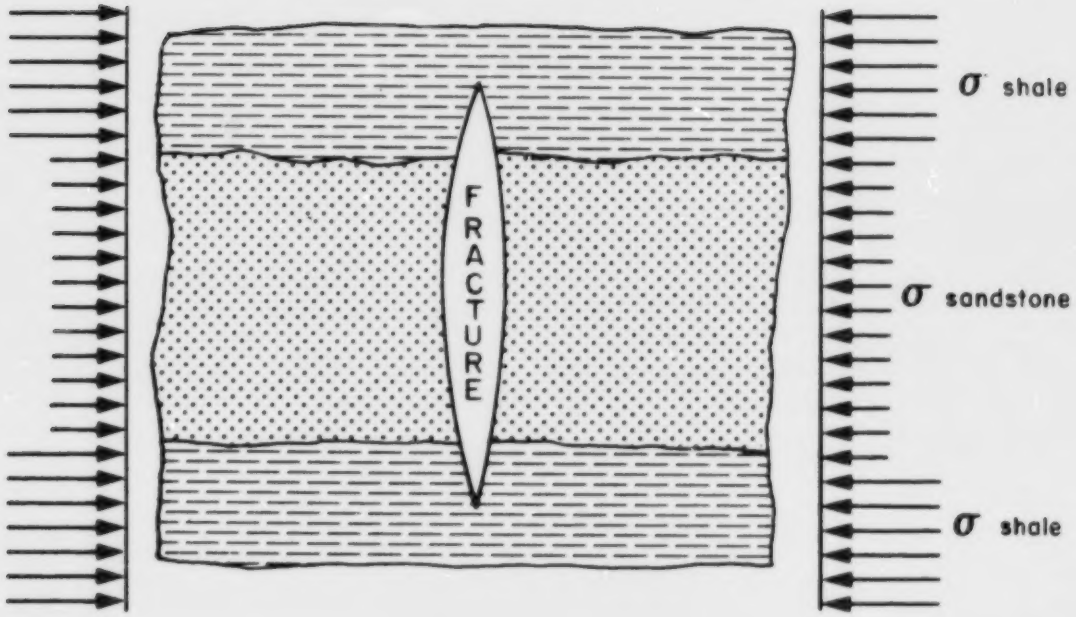


Shear-like Cracking at the Interface

Source: Clifton (1974)

FIGURE 2-6
HYDROFRACTURING FOR PREVENTION OF
ROCK/GAS OUTBURSTS

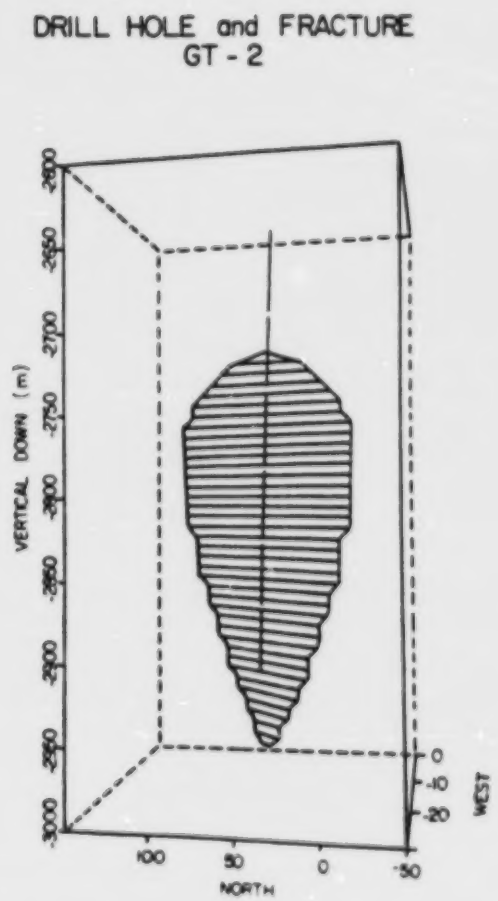
IN SITU STRESSES HIGHER IN BOUNDING STRATA



After: Simonson et al. (1976)

FIGURE 2-7
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

THREE-DIMENSIONAL PERSEPCTIVE OF THE FRACTURE ORIGINATING IN GT-2
(At 10° to the Fracture Surface at 2.81 km)



Source: Abou-Sayed et al. (1977)

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION 3 - CURRENT APPLICATIONS

Table of Contents

		Page
3.1	Introduction	3-1
3.2	Petroleum Industry	3-1
3.2.1	Formation Properties	3-2
3.2.2	Treatment Design	3-2
3.2.3	Treatment Fluids	3-4
3.2.4	Equipment	3-4
3.2.5	Case Histories	3-5
3.3	Coal Industry	3-6
3.3.1	Experience With Hydrofracturing Coal	3-7
3.4	Discussion	3-11

TABLE
(Following Text)

3-1 US Coalbed Characteristics

SECTION 3 - CURRENT APPLICATIONS

3.1 INTRODUCTION

The current practice of hydrofracturing is described as it presently applies to the petroleum and coal mining industries. There is considerable variance in the goals for each type of hydrofracture treatment; the largest difference being the type of material fractured - coal or sandstone/carbonates. A description of present fracturing techniques and material parameters is outlined in this section to provide a background to the proposed fracturing method outlined in Section 4.

3.2 PETROLEUM INDUSTRY

Hydraulic fracturing has been used in the petroleum industry since 1947 to increase production of oil and gas wells. Several wells in Canada were fractured in 1954, in the Pembina field. Without fracturing, oil from this field could not be economically produced. Since these first treatments, several thousand wells have been hydraulically fractured in this field alone. This is typical of the many other sandstone formations that exist in Canada. Because of the number of wells that require this form of stimulation, the fracturing industry has become highly competitive. This environment, along with gained experience, greatly improved the technology of hydraulic fracturing. This resulted in better treatment designs, better fluids and broader pumping capabilities, increasing the effectiveness of fractures for all reservoir situations.

Approximately 2500 hydraulic fracture treatments were completed in Canada in 1984.

3.2.1 Formation Properties

Oil and gas reservoirs are generally composed of sandstones or carbonates. Their properties vary in accordance with their depositional environment. Some of the main properties and average ranges found in Canadian formations are:

•	porosity	-	1. to 30%
•	permeability	-	0.01 to 10,000 mD
•	thickness	-	0.5 to 200 m
•	pressure	-	0.5 to 70 MPa
•	residual water saturation	-	5 to 80%
•	acid solubility	-	0 to 100%

Fracturing is utilized in both sandstone and carbonate formations. Classically, sandstones have been fractured using fluids containing proppants; carbonates, being acid soluble, have been fractured with acid. When fracturing carbonates with acid the fractured surface becomes etched, providing conduits for oil or gas flow; proppants, therefore, are not required. Current technology has shown propping unetched fracture faces apart with sand provides longer term and more predictable production increases at a reduced cost. Application has proven this technique.

3.2.2 Treatment Design

The object of most fracture treatments is to increase production of oil and gas reservoirs. The fracture parameters considered are treatment size, proppant concentration and types, fluid type and pumping rate. This must be balanced with the reservoir properties. The optimum design is the one that will provide the best production increase over the life of the well when compared to cost.

- **Treatment Size** effects the overall fracture length which, in turn, effects the well's production. Fracture treatment sizes range from placing a few tonnes of proppant, to treatments which place over 100 t of proppant.

- **Proppant Concentration** effects the conductivity of the fracture. As high a concentration as is possible results in the most conductive fracture. Maximum concentrations in a design can range from 600 kg to 1600 kg of proppant added to a cubic metre of liquid.

- **Proppant Size and Type** are mainly determined from the stress with which the formation closes on the proppant. Grain size can range from 40/60 mesh to 8/12 mesh with the smaller sizes having more strength. In situations where high closure stresses are encountered, high strength manufactured proppants are suitable.

- **Fluid Types** include high and low viscosity gels of water or hydrocarbon emulsions and foams. Selection is a complicated process involving reservoir evaluation, leak off control and proppant transport. Materials can be added to lower leak off, reduce surface tension or break the gels. Viscosities range from 1 to 250 MPa·s.

- **Injection Rate** is determined by well configuration, the fluid selected and the reservoir. Current trends are to lower injection rates to reduce stress on boundaries. Rates range from 1 to 15 m^3/min..

- **Other Considerations** such as pressure limitations, safety and clean-up time (the time required to remove the fracturing fluid from the reservoir) are also important factors in determining the best fracture treatment.

Equations have been developed to describe the reservoir and fracture. However, because the reservoir and treatment parameters simultaneously effect both fluid leak-off and fracture geometry, and both leak-off and fracture geometry affect each other, these equations require simultaneous solutions. Computer programs are used to provide solutions to the complicated problem.

3.2.3 Treatment Fluids

Fluids usually are either water or hydrocarbon based. The fluid is 'gelled' by the addition of polymers to form either cross-linked or linear molecular forms. The gelling of a fluid provides the increased viscosity necessary for sand transport and fracture stability. Some of the more common fluids in use are:

- gelled water
- carbon dioxide gas with gelled water
- gelled hydrocarbons
- emulsions (usually water external with a hydrocarbon)
- foamed fluids.

The choice of a fluid is dependent upon both the reservoir and the treatment requirements.

3.2.4 Equipment

Hydraulic fracturing requires specialized equipment. Fluids must be pumped at both very high rates and pressures in order to hydraulically fracture the formation rock. In a typical treatment as few as three to as many as twenty pumping units are used. The basic equipment required for a treatment follows:

Tanks	- cylindrical or square tanks used to store fluids for the hydraulic fracture treatment
Blender	- mix fluids with gelling agent or other chemicals prior to fracturing - mix sand with the fracturing fluids during pumping - discharge the slurry to the high pressure pumpers at rates of up to 15 m^3/min.
Pumper	- pump fluids at adequate rates and pressures to create and sustain a fracture

- typical units pump at pressures up to 69 000 kPa and have 750 kW of hydraulic power available per truck.

Treatment Analysis Unit
- monitors and records pressures, rates and sand concentrations
- tests frac fluids to ensure adequate properties.

All equipment can be either truck or skid mounted. Miscellaneous equipment such as CO_2 and N_2 transports may be required depending on the treatment to be completed.

3.2.5 Case Histories

Outlined are 3 case histories detailing the type of formation, the fracture treatment conducted and production results.

- **Case 1** involves a Slave Point (carbonate) formation at approximately 1400 m. Prior to fracturing the well, the well was tested and produced 1 m^3 of oil per day for 5 days.

  The fracture treatment was designed using the hydraulic fracture simulator (see Section 4.3.1). Vertical containment of the fracture was a problem. With this particular formation, the overall fracture height was estimated to be 25 m with 6 m of pay zone situated near the top of the fracture. In order to prop this interval and obtain sufficient fracture length a 100 t treatment with concentrations to 1600 kg/m^3 of fracturing fluid was required. An oil/water emulsion was selected for the fracturing fluid. Its high viscosity will control leak-off and carry the sand at the high concentrations. The rate was kept to 2.4 m^3/min to reduce vertical fracture growth.

  Post treatment production compared very well with that predicted. The oil production improved to 16 m^3/day immediately after the treatment, declining to 5 m^3/day after 100 days. Appendix B includes a graph of predicted and actual post fracture production, a copy of the well log, a drawing of one wing of the simulated fracture treatment, and a copy of the treatment program.

- **Case 2** involves a Slave Point (carbonate) formation at 1300 m. Prior to the fracture treatment this well produced a high of 6 m^3 of oil per day declining to 2 m^3 of oil after 3 years.

  The fracture treatment was designed using the hydraulic fracture simulator. As with most Slave Point formations, containing the fracture vertically is a problem. In this case the estimated fracture height was 29 m. There were two thin zones present, one (1.5 m) was located at the top of the estimated fracture height. The fracturing fluid was a cross-linked gelled water. 34 t of 20/40 mesh sand was used with concentrations taken to 1200 kg/m^3.

  Oil production after the fracture treatment improved to 9.0 m^3/day, declining to 4.5 m^3/day after one year. Appendix C includes a graph showing the actual pre and post fracture production, a copy of the well log, a drawing of one wing of the simulated fractured well, and a copy of the treatment program.

- **Case 3** involves a Basal Quartz (sandstone) formation at 1080 m. The well was drilled in 1969 and was abandoned because production of 0.5 m^3/day of oil was not economic; it had not been fractured.

  The well was re-entered by a different operator. It was hydraulically fractured in October 1984 using a treatment designed with the hydraulic fracture simulator. The fracturing fluid was an oil/water emulsion; 20 t of 20/40 mesh sand was used with concentrations to 1200 kg/m^3. The injection rate was kept to 2.2 m^3/min with a surface injection pressure of 14 MPa.

  Results of the fracture treatment were excellent. The well initially produced 24 m^3/day of oil with 15000 m^3/day of natural gas. Appendix D includes tables showing the actual post-fracture production data, the reservoir data and rheological properties of the fracturing fluid, a drawing of one wing of the simulated fracture and a copy of the treatment program.

3.3 COAL INDUSTRY

Almost all coal fracturing experience in North America has been in the Appalachian Region (i.e. the Pittsburgh Seam, the Pocahontas Seam)

and the Mary Lee/Blue Creek Seams of the Warrior Basin. With recent interest in producing gas from the deeply buried coals of the Western Basins (particularly the San Juan Basin and the Piceance Basin) experience in hydraulic fracturing coal will greatly increase in the coming years. Characteristics of the Eastern coals are summarized in Table 3-1. Total permeabilities to one phase flow (gas or water but not both simultaneously) seem to range from 2 to 10 millidarcies (mD). For single phase fluid flow these high permeabilities do not provide increased production after hydraulic fracturing. However, if both gas and water flow simultaneously as expected for a water saturated coal, the effective permeability to both gas and water is a small fraction of the total permeability. This is particularly true for coal which has a strong affinity to water; irreducible water saturation for coal is approximately 70% (Jones, 1984). Under these conditions increased gas production is possible upon hydraulic fracturing. It is for this reason coal wells are normally completed by hydraulic fracture treatment. The experience gained from these fracture treatments is outlined below.

3.3.1 Experience With Hydrofracturing Coal

Since 1969, a large number of hydraulic fracture stimulations have been applied to coalbeds. Little or no site characterization was performed in support of treatment designs and post-stimulation analyses. Reported results are limited to observations; no attempts were made to better control and optimize fracture treatments. A higher proportion of these treatments have been in mineable coal. The purpose was to more effectively drain methane from coal ahead of mining (the benefits of fracturing were outlined earlier). Initially water based gels were used as fracturing fluids. More recently fracturing has been with nitrogen foam. The advantages of using foam rather than gelled fluids in coals are:

- Foam treatments are very clean. On flow back most of the stimulation fluids are removed from the coalbeds in less than one day. This is in contrast to unbroken gels found near the wellbore in coal.

- On-site water requirements are about 60% to 80% less with foam as compared to similar size volume treatments with gels.

- Leakoff to the coalbed appears to be reduced with foam.

A comprehensive review of experience in fracturing coal has been compiled by Lambert et al, 1980b; their conclusions are briefly summarized below.

- The fractures are shorter than predicted. The longest measured sand-packed fracture length was 416 feet. This was for a fracture created using a light gel fluid in the Illinois No.6 Coalbed.

- The reasons for the shorter fracture lengths is the high treatment pressures. Appendix E shows that treatment pressure gradient in a large number of cases greatly exceeds 0.023 MPa/m. The high pressure results in wider fractures of shorter lengths. Reasons for the high pressure in hydrofracturing coal are not known.

- Nearly all of the induced fractures observed from within underground coal mines are vertically oriented. This is not surprising since most coals are located in tectonically relaxed areas where the greatest principal rock stress direction results from the overburden.

  Horizontal fractures have resulted where injection pressures exceed the calculated overburden stress in wells as deep as 335 m. Many fractures are of the form shown in Figure 2-5. Where both horizontal and vertical fractures form, their extent will be shorter than predicted.

- A close correlation exists between natural fractures and induced fracture directions. The induced fractures follow both the face cleat and butt cleat directions. The dominant length fracture follows the face cleat direction.

- Since coalbeds tend not to be very thick (<3 m) fractures initiated in the coal will tend to propagate into the roof and/or floor with increased fracture lengths.

  One underground well site study showed that induced fractures do indeed enter into very hard roof rock even when low surface injection rates (26.5 L/s) and pressures (9.65 MPa) are used.

  The condition of the interface between coalbed and the overlying roof rock can limit the upward growth of hydraulically induced fractures. Underground examinations indicate that the induced fractures are more likely to remain in the coalbed when the overlying shale/coal interface is very abrupt and weakly bonded. Such weakly bonded interfaces have been recognized in mine areas where the contact between coal and shale is highly polished and striated (slickensided). Where these types of boundary conditions occur, fracture partings have frequently spread out horizontally within the interface area rather than grow vertically into the overlying roof.

- Effect of fracturing on the subsequent stability of the roof rock is a controversial subject despite the optimistic outlook conveyed in published reports. Lambert et al (1980) cite several examples. Sample cases are cited below (for drillhole reference see Appendix E):

  - The findings at two borehole sites where guar gum gel had been used to treat the Illinois No.6 Coalbed and the Pittsburgh Coalbed are described. The fractures propagated from both sites were vertical, and were contained completely within the respective coalbeds. The widths of these fractures varied according to the relative viscosity of the fluids used. The less viscous fluid produced fractures ranging from 3.2 mm to 12.7 mm wide while the more viscous fluid formed fractures up to 63.5 mm in width. There appeared to be no adverse effect on the stability of the overlying or underlying rock strata, or mining operations. Periodic observations over more than two years showed that no deterioration of mine roof or floor had taken place where the sand filled fractures were earlier exposed.

  - Two boreholes, designated TW3 and TW4, were stimulated in the Mary Lee Coalbed at the US Steel's Oak Grove Mine, Jefferson County, Alabama. Foam was used as the stimulation fluid. The sand filled fractures

that propagated from these two boreholes were vertical, very thin, and began about 0.9 m up from the base of the 1.5 m thick coalbed and continued for an undetermined distance into the overlying roof strata. Mine management's evaluation of the mine roof was as follows (Lambert, 1980b; p 151):

"Because the roof of the mine in the general vicinity of TW4 was of a quality which required installation of more roof support than used in many other portions of the mine, it was difficult to assess the effect of the fracture on the mine roof at this location. However, no further increment of supplemental roof support was required at the base of the borehole or along the fracture wings.

"The roof in the general area of TW3 was of a quality typical of most of the mine developed to date; however, in the immediate area of the bottom of TW3 in which both the upper and lower coal seams had been fractured, it was necessary to install supplementary roof support. This supplemental roof support was required when mine management observed roof movement along the west rib of the entry driven due north of the bottom of the borehole, additional draw slate separation, roof becoming excessively drummy, and water seeping out of cracks in the roof. The supplemental roof support consisted of boxing the intersection immediately to the south of the borehole with 15.2 cm I-beams, installing four inch I-beams supported by timbers for distances of 21.3 m to the east and 12.2 m to the north of the borehole, and installing 3.0 m long expansion steel anchored roof bolts between the standard 1.2 m long resin bolts to ensure that the bolts were anchored in solid rock above the upper coal seam.

"Installation of the supplementary supports required additional time as well as close inspection by mine management to ensure its adequacy; however, it was possible to mine through this area without experiencing any roof fall during mining operations".

The development of horizontal fractures above the interval being mined is, perhaps, potentially the worst possible roof condition that can be directly attributable to stimulation. Stimulation fluid pumped into the TW5 borehole at the Mary Lee Coalbed in the Oak Grove Mine, Jefferson County, Alabama, was found to

have spread horizontally within an interface area between the coalbed and an overlying shale rock unit. Within the test area, the coalbed's surface at this interface was highly polished and striated (slickenside surfaces), indicating that the coalbed and shale had not been tightly joined together prior to stimulation. It was concluded, therefore, that the horizontal penetration of fluid did not change the original 'weak' character or strength of the bond between the coalbed and the overlying roof rock. Even though there was no visible damage or excess water or gas drainage, precautionary supplemental roof support (steel I-beams) were installed for small distances away from the TW5 borehole site.

The comparatively small amount of information available on roof stability, and the significantly different character of the results, suggests that the effects of hydraulic stimulation on roof stability cannot be fully appreciated at this time.

3.4 DISCUSSION

Hydrofracturing of oil and gas wells has been undertaken since 1947 and for coal demethanization since 1969. From the beginning of its development, research has continued to allow better understanding of the mechanisms of hydrofracturing. It should be noted, therefore, that hydrofracturing, is not a new frontier technology, but has been proven successful by practical application in both the petroleum and coal industries.

In the petroleum industry, where hydrofracturing costs for a single well may exceed $100,000, mathematical modelling of the fracture geometry and production has proven useful to pre-determine sand sizes, fracturing fluids, volumes, sand concentrations and flow rates. Modelling of fractures for the coal industry has been limited, likely due to the lower fracturing costs and the tendency of fractures to remain in the coal seam.

AMCL

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION 3 - CURRENT APPLICATIONS

Table of Contents

		Page
3.1	Introduction	3-1
3.2	Petroleum Industry	3-1
3.2.1	Formation Properties	3-2
3.2.2	Treatment Design	3-2
3.2.3	Treatment Fluids	3-4
3.2.4	Equipment	3-4
3.2.5	Case Histories	3-5
3.3	Coal Industry	3-6
3.3.1	Experience With Hydrofracturing Coal	3-7
3.4	Discussion	3-11

TABLE
(Following Text)

3-1 US Coalbed Characteristics

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION 4 - OUTBURST CONTROL POTENTIAL

Table of Contents

		Page
4.1	Introduction	4-1
4.2	Outburst Causes	4-1
4.3	Treatment Design	4-3
4.3.1	Description of Hydraulic Fracture Simulator	4-4
4.3.2	Assumptions	4-4
4.3.3	Recommended Treatment	4-6
4.3.4	Results of Simulated Treatment	4-7
4.4	Discussion	4-9

TABLE
(Following Text)

4-1 Parameters Affecting the Fracture

FIGURES
(Following Table)

4-1 Stress Axes Relative to Roadway

4-2 Schematic Representation of Outburst Phenomenon

.....Cont'd

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION 4 - OUTBURST CONTROL POTENTIAL

Table of Contents Cont'd

FIGURES

4-3 Proppant Distribution at Closure (Permeability 0.05 mD)

4-4 Proppant Distribution at Closure (Permeability 0.01 mD)

4-5 Proppant Distribution at Closure (Permeability 0.1 mD)

4-6 Proppant Distribution at Closure (Sand Concentration 480 kg/m^3)

4-7 Proppant Distribution at Closure (Fracture Height 3 m)

4-8 Gas Production Rates at Selected Permeabilities

4-9 Gas Production Rates at Selected Internal Gas Pressures

4-10 Reservoir Pressure After 90 Days Production Unstimulated (Permeability 0.05 mD)

4-11 Reservoir Pressure After 90 Days Production Fractured (Permeability 0.05 mD)

4-12 Reservoir Pressure After 90 Days Production Fractured (Permeability 0.01 mD)

AMCL

SECTION 4 - OUTBURST CONTROL POTENTIAL

4.1 INTRODUCTION

In order to design a program for controlling outburst problems of the type experienced in No.26 Colliery in Nova Scotia, it is necessary to consider the conditions that lead to the outbursts. Outlined in this section is a hypothesis of the outburst cause and a conceptual design of the method of reducing the probability of further outbursts.

4.2 OUTBURST CAUSES

The observed conditions favourable to creating outbursts are:

- sandstone channels near coal seam
- thin siltstone partings in sandstone
- burial depths of greater than 750 m
- extremely low permeability of the sandstone
- presence of methane in the sandstone.

Stress determinations made in No.26 Colliery (Golder Assoc. 1984) at a depth of 852 m below msl (762 m of rock cover) are reported.

$$\sigma_x = 23.3 \pm 3.26 \text{ MPa}$$
$$\sigma_y = 24.98 \pm 2.97 \text{ MPa}$$
$$\sigma_z = 25.27 \pm 1.16 \text{ MPa}$$

These stress magnitudes indicate a nearly isotropic stress condition which by itself is not likely to create an outburst condition.

The methane gas detected immediately after an outburst takes place indicates that methane gas trapped in the formation is released. In situ

gas pressure tests in sandstone in the outburst area have measured gas pressures in the order of 2.8 MPa. This pressure could only be achieved by first pressurizing the hole with nitrogen to stimulate methane flow (Aston and Cain, 1985). Working back from gas volumes determined after outbursts gave a range in situ gas pressures of 0.28 MPa and 47 MPa, assuming all gas came from the outburst rockmass.

The mechanism which causes the outburst is postulated to be a combination of internal gas pressure which overcomes the tensile strength of the rock mass when there is an alteration in the triaxial stress field, due to mining. One of the confining stresses will approach zero near the roadway. The natural tensile strength of the immediate roof rock will be approximately 8-12 MPa (Aston and Cain, 1985), however, fractures will reduce this value.

Blasting will cause compressional and tensional shock waves to pass through the rockmass. The tensile component will tend to reduce the confining pressure on the pore spaces.

A simplified analogy is illustrated in Figure 4-1, which shows a two-dimensional representation of bonded grains with interstitial pores containing methane at a pressure "P". Initially stresses are assumed to be equal in all directions and unaffected by mining ($\sigma_a \simeq \sigma_b \simeq \sigma_c$, Figure 4-2A). As a roadway approaches the grains, σ_a will be reduced (Figure 4-2B) and the pore prescure will approach the tensile strength of the sand grain bonds.

When blasting is undertaken, in proximity to the grains, the resultant wave form ("P" wave) will set up an oscillating longitudinal wave comprising compressive and tensional cycles (Bauer et al, 1981). The tensional component of these waves will further reduce σ_a and cause failure of grain bonds in the σ_b/σ_c plane (Figure 4-2C). The bond strengths in the other two planes which are held in compression by σ_b

and σ_c do not fail. This failure mechanism would explain the 'onion skin' exfoliation characteristic of the outburst sandstone.

The aim of a hydrofracturing program would be to reduce the pore pressure prior to the alteration of the stress field by mining. A total gas extraction is not required, however, the gas pore pressure will have to be reduced below the point where the combination of pore pressure, blasting and the decrease in confining stress due to mining does not exceed the tensile strength of the sandstone.

The rate and absolute amount of pore pressure reduction is greatly dependent on the initial pore pressure. Higher pore pressures will have a higher gas production rate. For this reason it is recommended that accurate in situ gas pressures be measured. This data could also be used to create better mathematical models for predicting potential outburst conditions.

4.3 TREATMENT DESIGN

To optimize treatment size, fracture spacing and drainage time, it is valuable to simulate the reservoir and fracture treatment. Accurate reservoir properties are required for reliable simulations. Changes in parameters such as permeability and pore pressure effect fracture design and gas drainage. Because much of the information was not available, some general assumptions were made to run computer simulations. Before an actual hydrofracturing demonstration is conducted it is recommended that reservoir parameters be more accurately determined, to better design the fracture treatment.

All parameters required to run the reservoir model are listed in Table 4-1. Most were obtained from a case history file (Aston, personal communication, 1984).

4.3.1 Description of Hydraulic Fracture Simulator

The **Nowsco FRAC SURE Simulator** as described by Settari (1979) models three-dimensional compressible two-phase flow and heat transfer in a reservoir simultaneously with initiation and propagation of hydraulic fracture. Nowsco started using the precursor to its present simulator to design fracture treatments in 1980. Various other models have been evaluated. Although other simulators may handle various facets of the fracturing and production process better, the current Nowsco FRAC SURE model was found to be the most practical combination of three-dimensional crack generation, fluid leakoff from the fracture, proppant transport, heat loss and production. Nowsco's confidence in the model has increased with experience and several hundred successful applications of the technology.

- predicting the time and pressure at which the fracture initiates
- predicting the length of a stabilized fracture and the rate of fracture growth
- closing and reopening the fracture depending on production/injection schedule
- predicting proppant distributions during placement and closure
- predicting reservoir pressure, saturation and well production before and after fracturing,

4.3.2 Assumptions

Reservoir Geometry The actual geometry of the sandstone above the coal will have an effect on the simulation process. It appears that the sandstone has been deposited in channels, however, the widths and thicknesses of the channels are unknown. For simulation purposes an approximate width of 240 m and thickness of 6 m has been assumed.

The width of 240 m was determined from boreholes drilled into the roadway roof. In actual fact the channels may be much wider and may be a continuous sheet of sandstone varying in thickness.

The thickness of 6 m was obtained from a cross-section of one of the outbursts. Exactly how this thickness varies in either direction from the outburst section is difficult to determine. One can only assume that it will remain more constant along its length and will thin out across the width. The reservoir simulator cannot account for changes in thickness and so 6 m was used.

Fracture Containment It was assumed that the fracture would remain in the sandstone and have a height equal to the thickness of the sandstone. There is a strong possibility, however, that in areas where the sandstone contacts the coal, the fracture will extend into the coal. Once this happens, continued extension of the fracture would likely occur in the weaker coal material.

Fracture Orientation No particular direction for the fracture was assumed. If the fracture grew across the width and the thickness of the sandstone changed across the width, the actual fracture geometry would be different from that simulated, and the results would be affected.

Formation Pressure The formation pressure is probably the most important reservoir parameter since it is this parameter that must be reduced to prevent outbursts. The pressure determines the quantity of gas in place, provides the driving force to produce it and effects the rate of fluid leak-off as the fracture treatment is being pumped. In the sandstones above the coal, this parameter has not been accurately measured. In the petroleum industry it is not uncommon to find a vertical pressure gradient ranging from 4.0 kPa/m to 14.0 kPa/m. Since the pressure in this case was

assumed to be quite high, a gradient of 11.0 kPa/m was used. This corresponds to an internal pore pressure at 8600 kPa. Simulations were also made using 5500 kPa and 3500 kPa.

Permeability An accurate measure of permeability was not available. Permeability affects the rate of fluid leak-off into the formation during the treatment, and the gas production after the treatment. A permeability of 0.05 mD was used, however, simulations were also made using 0.1 mD and 0.01 mD.

Water Saturation The water saturation is the percentage of pore space occupied by water. Normal saturations of non-mobile water found in petroleum reservoirs range from 15% to 35%. A water saturation of 20% was used for this study. This parameter, usually measured using a resistivity log, is important since change in water saturation will result in change in the relative permeability of both the gas and water.

4.3.3 Recommended Treatment

Fluid Type Water, gelled with a hydroxypropyl guar gum, is the most practical fracturing fluid to be used when fracturing from within the workings of an underground mine, because:

- water is not flammable
- it requires no special or extra equipment for storage and pumping as does nitrogen when using foam
- the gellant can easily be mixed into the water in the mine
- almost any viscosity can be obtained, resulting in high sand carrying capability and low fluid leak-off
- the gellant can easily be broken at controlled times to maximize the possibility of trapping proppant across the entire permeable sandstone section.

Proppant When fracturing a sandstone it is important that a proppant be used to keep the fracture from closing. Two tonnes of 20/40 mesh sand is recommended, increasing to concentrations of 960 kg/m^3.

Rate For the given reservoir properties a pump rate of 0.64 m^3/min is sufficient to conduct the treatment. Rates lower than this may produce problems with blending, moving the slurry through long lengths of horizontal pipe, and leak-off rates exceeding pump rates.

Fluid Volume The fluid volume required to pump 2 t of sand at concentrations of 960 kg/m^3 is 6.3 m^3.

Monitoring System A system of monitoring the fracture treatment is essential. The treatment parameters that must be recorded are:

- injection pressure at point of pump
- pumping rate
- sand concentration

In addition to the injection pressure at the pumps the pressure at the packer should be recorded. This pressure will be the true fracturing pressure since tubing friction is by-passed.

4.3.4 Results of Simulated Treatment

The parameters used to describe the reservoir are listed in Table 4-1. Because the majority of these parameters are only estimated, a number of computer runs were made using a range of values. The parameters that have the greatest effect on the final outcome are reservoir pressure and permeability.

Fracture Geometry The proppant distribution within the fracture and the fracture lengths for various situations are shown in Figures 4-3 through 4-7. Figure 4-3 is the geometry using the parameters outlined in Table 4-1. The following figures are variations thereof.

Figures 4-4 and 4-5 show the effects that permeability have on geometry. If the reservoir has a higher permeability, both the overall fracture length and the closure time are reduced. The reduced closure time results in a more fully propped fracture.

Figure 4-6 shows the proppant distribution for a treatment using a maximum proppant concentration of 480 kg/m^3, and 1.0 t of sand. Using the lower sand concentrations a sand bank resulted since the increased fluid volume extended the closure time.

Figure 4-7 shows the proppant distribution for a situation in which the fracture height was only 3 m. Again, only 1.0 t of sand was used, since a larger fracture treatment would exceed the reservoir boundary.

Post Treatment Production Figures 4-8 and 4-9 demonstrate how effective a fracture treatment can be for gas production. Both figures show simulated daily production for situations with and without a fracture treatment. A back pressure of 350 kPa at the drillhole collar has been used. A reduction in this back pressure will reduce the time for methane drainage.

The effects of changes in permeability and internal pore pressure are also shown. Figure 4-8 shows how permeability changes gas production and Figure 4-9 shows how pressure affects it.

AMCL

Pressure Drawdown Profiles Figure 4-10, 4-11 and 4-12 show the simulated pressure distribution in the reservoir after 90 days of production. The simulated drawdown for a reservoir is shown in Figure 4-10, while Figures 4-11 and 4-12 show the effect of fracture stimulation. By comparing Figures 4-10 and 4-11 the effect that the fracture has on pressure draw-down can be seen. The reservoir properties used in these two cases are identical.

The effect of permeability can be observed by comparing Figures 4-11 and 4-12. The pressure is drawn down much quicker if the permeability is high. The permeability used in the simulation to produce Figure 4-12 is 0.01 mD as compared with 0.05 mD to produce Figure 4-11.

These types of graphs can be used to determine fracture spacing once the required pressure draw-down is determined.

4.4 DISCUSSION

Outbursts of the type experienced in the No.26 Colliery in Nova Scotia are related to:

- internal gas pressure
- blasting
- an alteration of the triaxial stress configuration due to mining.

The outbursts are a result of the overlying sandstone strata failing in tension. The parameter that can be altered to reduce the stress in the rockmass is the internal gas pressure. A reduction in the pore pressure will reduce the stress differential and, therefore, the potential for outbursts.

Hydraulic fracturing is an effective method of reducing the pore pressure within the sandstone. The final treatment design and spacing will be dictated by the required pressure reduction, the allowable drainage time, the sandstone properties and geometry and the fracture orientation.

A reservoir model can be a tremendous tool for fracture treatment design. It simultaneously considers all the factors that affect the fracture treatment. It also predicts post treatment production and provides a pressure distribution of the reservoir for any time period after the treatment.

To fully utilize the model, accurate information about the sandstone reservoir must be known. The areas that will require better definition are:

- sandstone channel geometry
- stress orientation
- reservoir properties.

The most important reservoir properties that must be determined are permeability and internal gas pressure. Both parameters have a strong influence on the fracture treatment and the methane drainage after the treatment. The object of hydraulic fracturing is to reduce the internal gas pressure. It is, therefore, important to know what this pressure is initially and what it must be reduced to.

TABLE 4-1
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

PARAMETERS AFFECTING THE FRACTURE

FORMATION PARAMETER	
Reservoir Properties	
Permeability	0.05 mD
Porosity	5.0 %
Pay Thickness	6.1 m
Reservoir Pressure	8.6 MPa
Water Saturation	20.0 %
Reservoir Temperature	21.0 °C
Rock Properties	
Overburden Stress	22.1 MPa
Fracture Initiation Pressure	20.7 MPa
Young's Modulus	16.5 GPa
Poisson's Ratio	0.17
Tensile Strength	5.5 MPa
Area Simulated	240 m x 240 m
TREATMENT PARAMETERS	
Frac Fluid	water gelled with hydroxypropyl guar gum gellant at 7.2 kg/m^3, yielding a viscosity of 60 cp.
Proppant	2.0 t of 20/40 mesh sand
Slurry Injection Rate	0.64 m^3/min

FIGURE 4-1

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

STRESS AXES RELATIVE TO ROADWAY

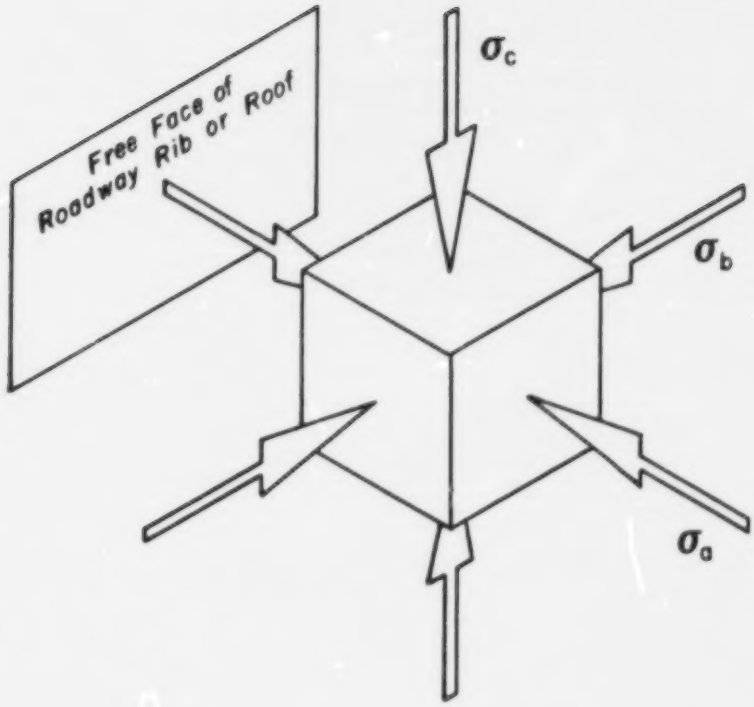
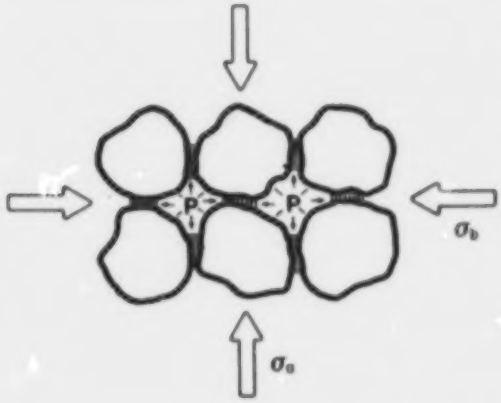


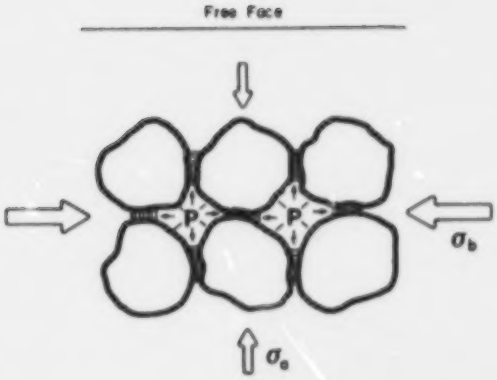
FIGURE 4-2
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SCHEMATIC REPRESENTATION OF OUTBURST PHENOMENON

A) In situ - steady state

$\sigma_a = \sigma_b \simeq \sigma_c$





B) Effect on stress configuration caused by new roadway

σ_a reduced

$\therefore \quad \sigma_a < \sigma_b \simeq \sigma_c$

C) Onion Skin Exfoliction and Outburst Phenomenon

σ_a approaches 0

σ_b and σ_c reduced

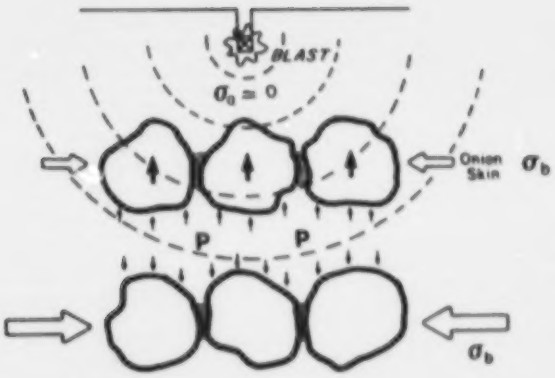
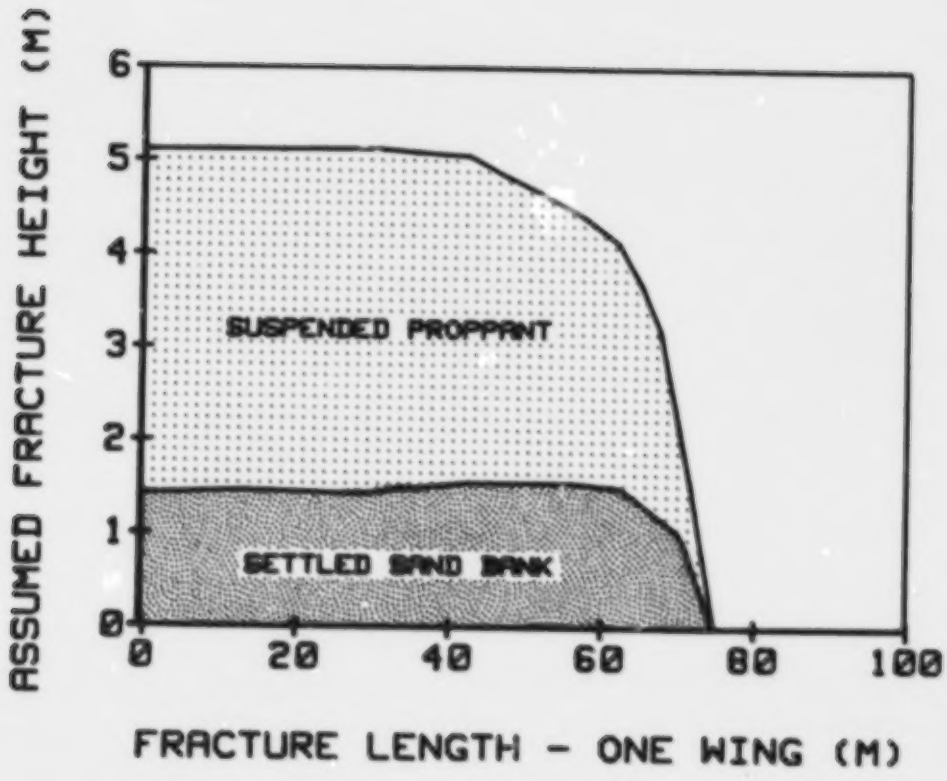


FIGURE 4-3
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

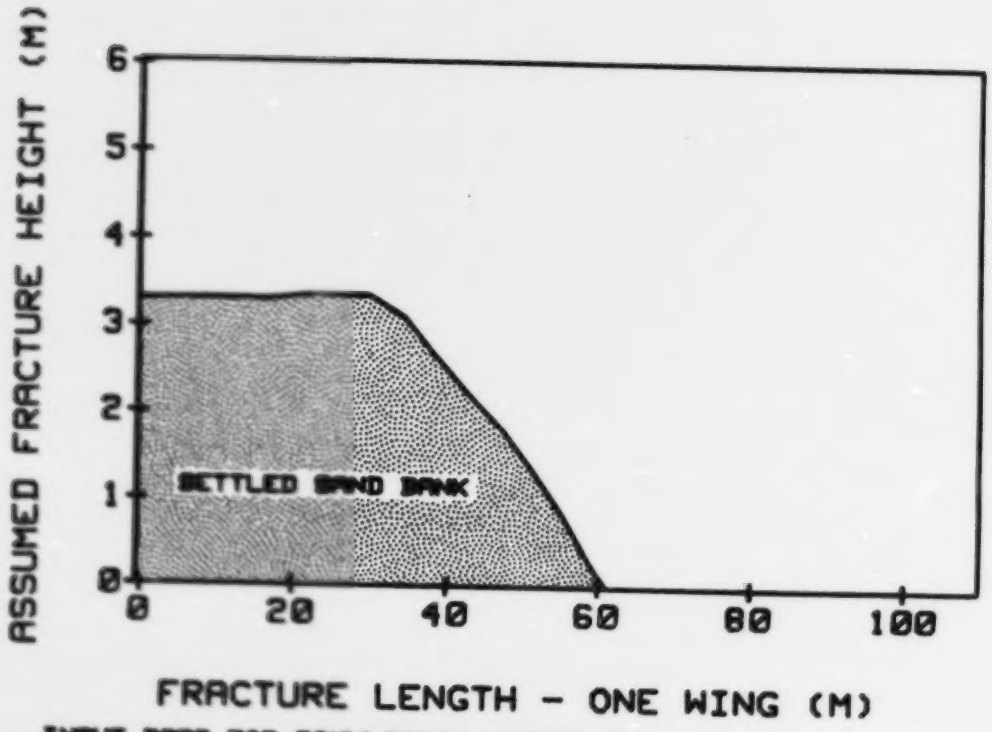
PROPPANT DISTRIBUTION AT CLOSURE
(Permeability 0.05 mD)



INPUT DATA FOR SIMULATION LISTED IN TABLE 4-1

FIGURE 4-4
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

PROPPANT DISTRIBUTION AT CLOSURE
(Permeability 0.01 mD)



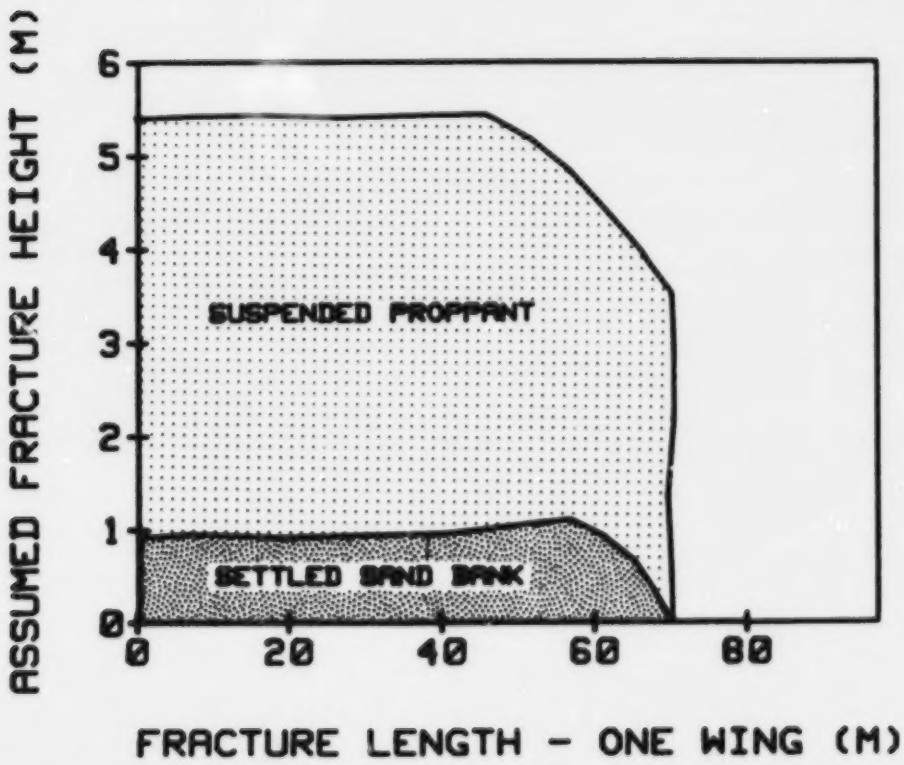
INPUT DATA FOR SIMULATION LISTED IN TABLE 4-1
PERMEABILITY CHANGED TO 0.01 md

FIGURE 4-5

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

PROPPANT DISTRIBUTION AT CLOSURE

(Permeability 0.1 mD)



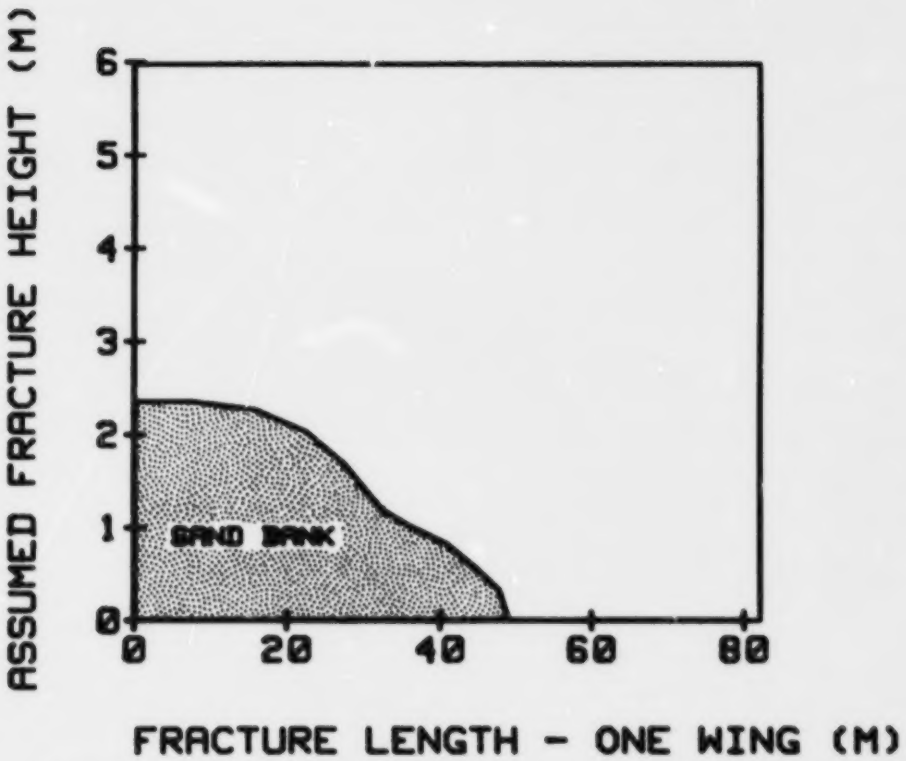
INPUT DATA FOR SIMULATION LISTED IN TABLE 4-1
PERMEABILITY CHANGED TO 0.10 md

FIGURE 4-6

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

PROPPANT DISTRIBUTION AT CLOSURE

(Sand Concentration 480 kg/m^3)

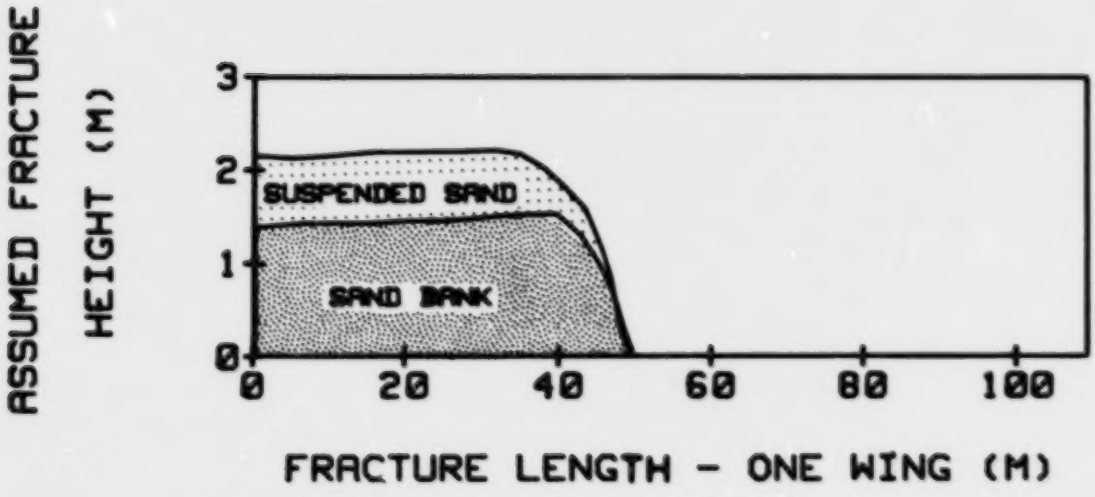


INPUT DATA FOR SIMULATION LISTED IN TABLE 4-1

MAXIMUN SAND CONCENTRATION 488 KG/M3

FIGURE 4-7
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

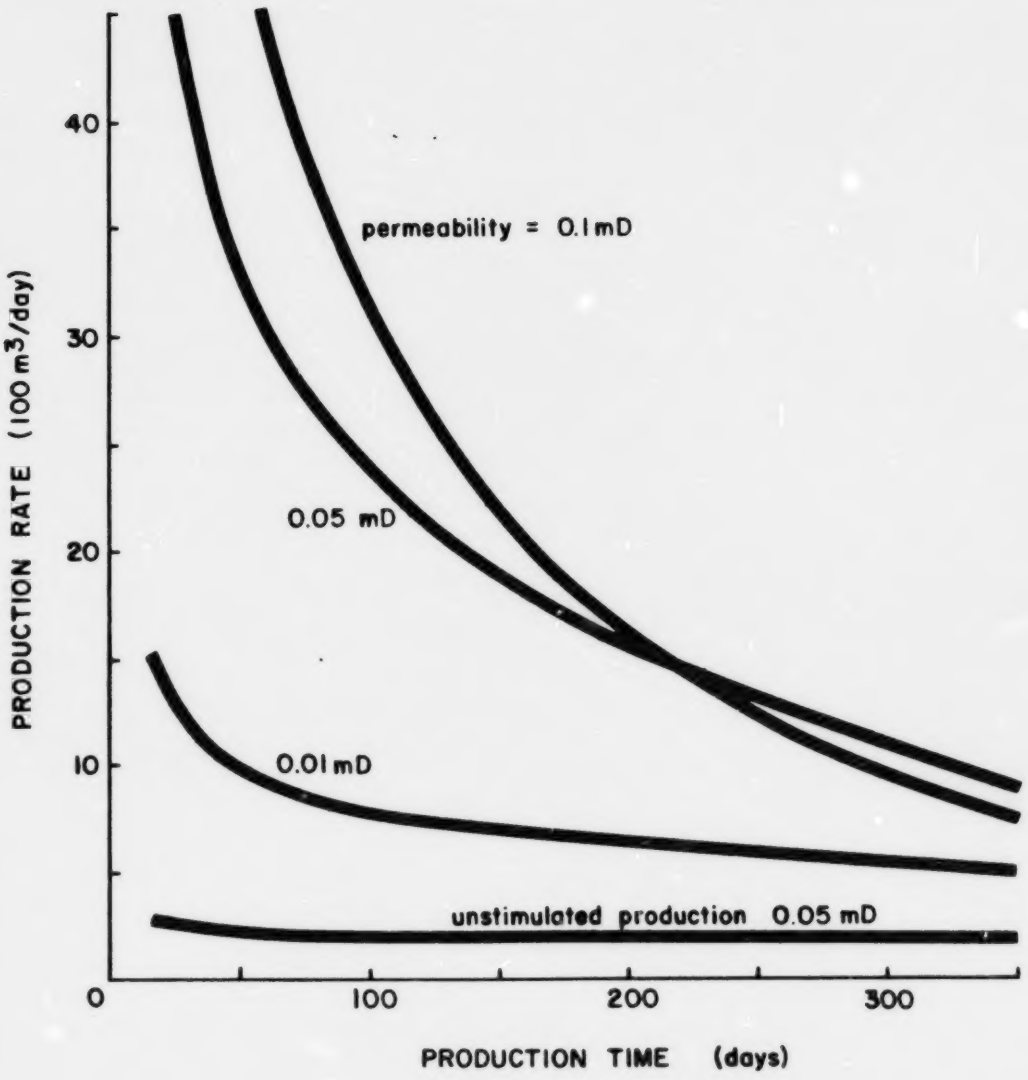
PROPPANT DISTRIBUTION AT CLOSURE
(Fracture Height 3 m)



INPUT DATA FOR SIMULATION LISTED IN TABLE 4-1
FRACTURE HEIGHT CHANGED TO 3 METERS

FIGURE 4-8
HYDROFRACTURING FOR PREVENTION OF
ROCK/GAS OUTBURSTS

GAS PRODUCTION RATES AT SELECTED PERMEABILITIES

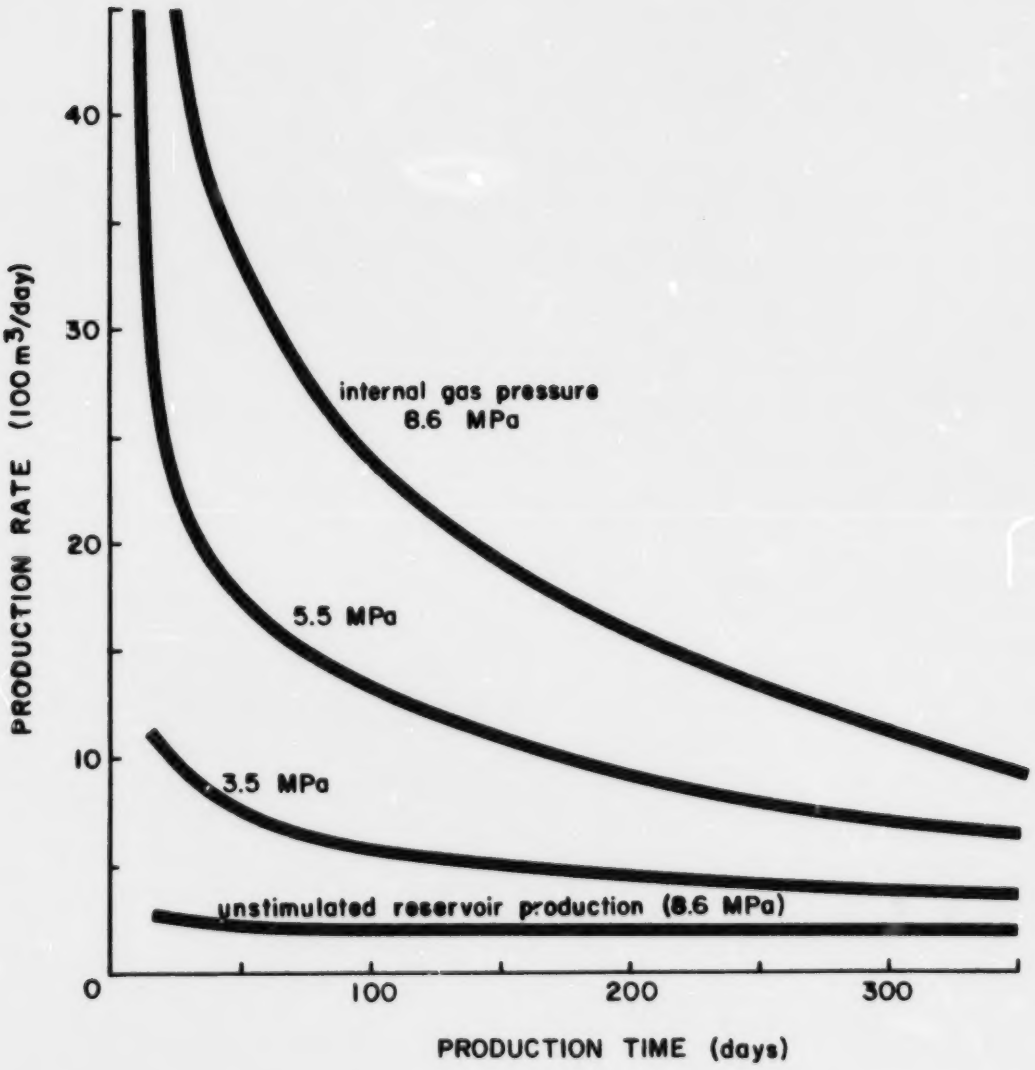


Note: Other input parameters, see TABLE 4-1

FIGURE 4-9

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

GAS PRODUCTION RATES AT SELECTED INTERNAL GAS PRESSURES



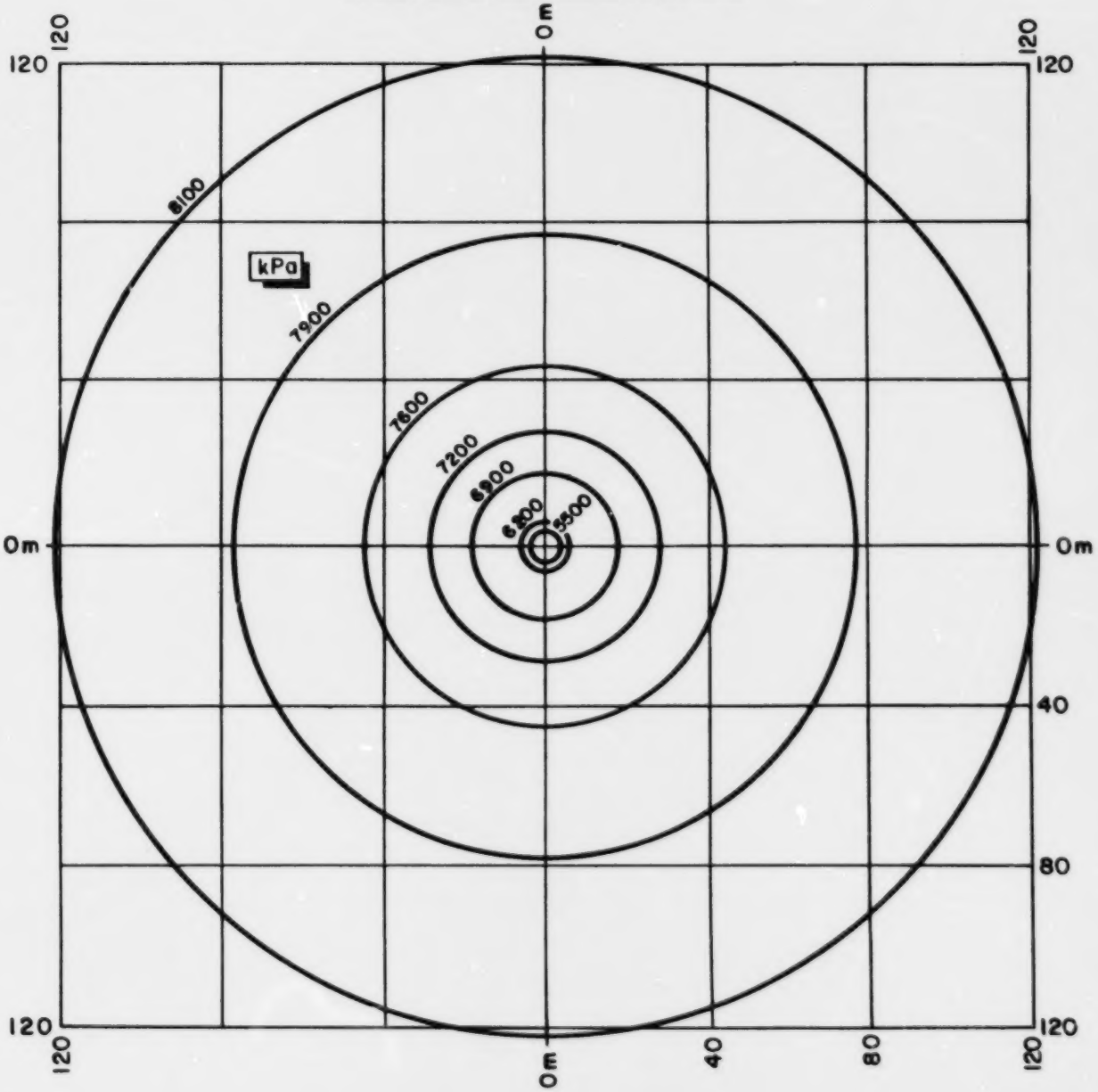
Note: Other input parameters, see TABLE 4-1

FIGURE 4-10

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

RESERVOIR PRESSURE AFTER 90 DAYS PRODUCTION

Unstimulated (Permeability 0.05 mD)
Initial Reservoir Pressure 8600 kPa



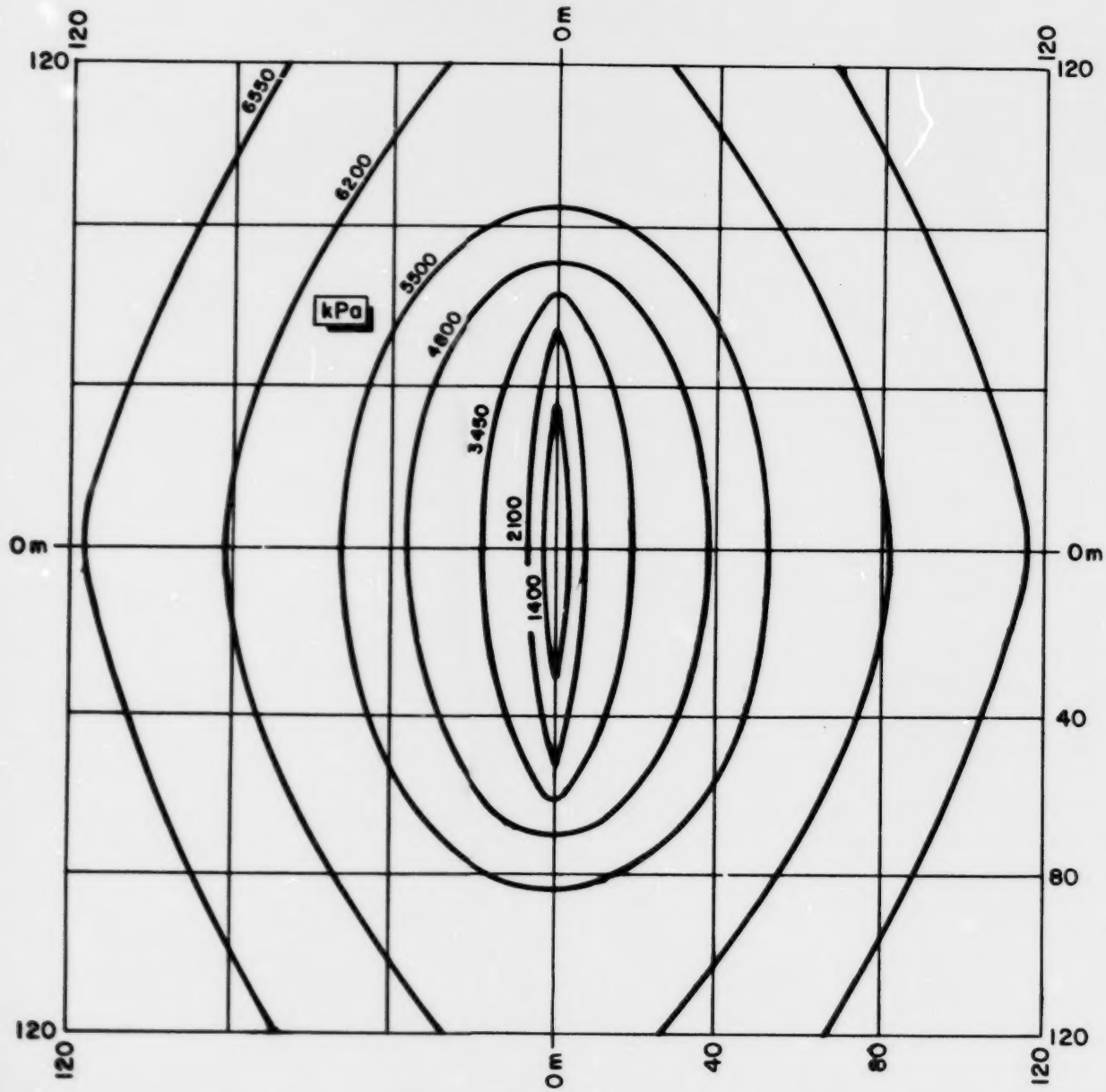
Note: Other input parameters, see TABLE 4-1

FIGURE 4-11

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

RESERVOIR PRESSURE AFTER 90 DAYS PRODUCTION

Fractured (Permeability 0.05 mD)
Initial Reservoir Pressure 8600 kPa



Note: Other input parameters, see TABLE 4-1

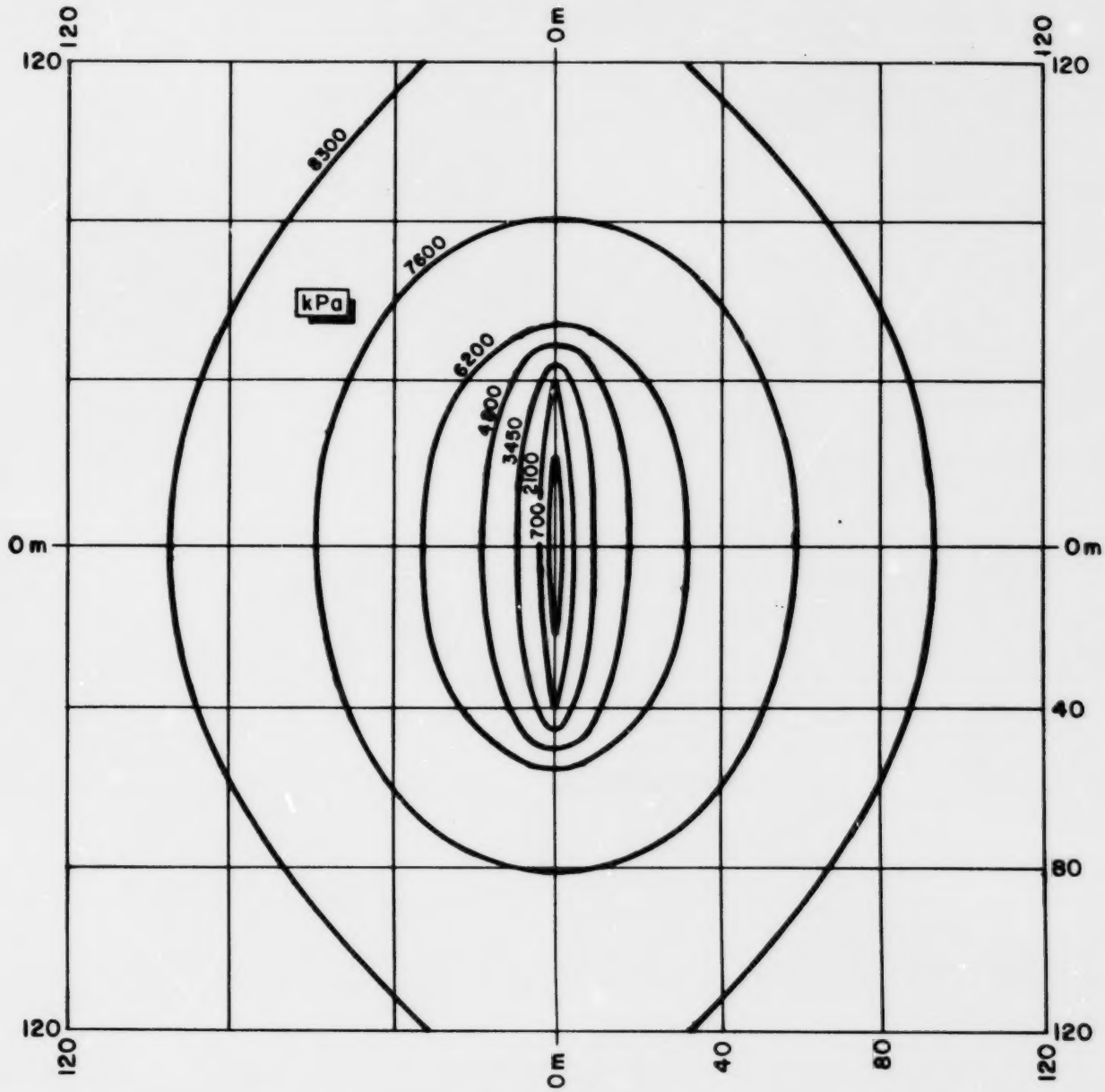
AMCL

FIGURE 4-12

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

RESERVOIR PRESSURE AFTER 90 DAYS PRODUCTION

Fractured (Permeability 0.01 mD)
Initial Reservoir Pressure 8600 kPa



Note: Other input parameters, see TABLE 4-1

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION 5 - DEMONSTRATION PROGRAM FOR HYDROFRACTURING UNDERGROUND

Table of Contents

		Page
5.1	**Introduction**	5-1
5.2	**Directional Drilling**	5-2
5.2.1	Introduction	5-2
5.2.2	Constraints to Drilling	5-2
5.2.3	Drilling Equipment	5-3
5.2.4	Demonstration Program	5-6
5.3	**Packers**	5-7
5.4	**Hydrofracturing Equipment**	5-8
5.4.1	Pumping	5-9
5.4.2	Sand Mixing	5-9
5.4.3	Tankage	5-10
5.4	**Discussion**	5-10

TABLE
(Following Text)

5-1 Specification for Slim Hole Injection Packers

FIGURES
(Following Table)

5-1 Torque - Pressure Drop Curve Downhole Motor

.....Cont'd

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION 5 - DEMONSTRATION PROGRAM FOR HYDROFRACTURING UNDERGROUND

Table of Contents Cont'd

5-2 Fluid Flowrate Curve for Downhole Motor

5-3 Power Curve for Downhole Motor

5-4 Downhole Motor with Deflection Shoe

5-5 Gas Reservoir Exploration Drillhole

5-6 Typical Open Hole Injection Packer

5-7 Limiting Differential Pressure for Various Packers

5-8 Data Sheet: High Pressure Pump

5-9 Data Sheet: Slurry Averaging System

SECTION 5 - DEMONSTRATION PROGRAM FOR HYDROFRACTURING UNDERGROUND

5.1 INTRODUCTION

Prior to implementation of a 'Production Scale' hydrofracturing program, a smaller scale demonstration is suggested. This section outlines the recommended procedures necessary to perform a successful frac and identify the type of equipment to be used.

A review of the literature has revealed that most horizontal drilling and hydrofracturing in the coal industry has been aimed only at coal seams, mainly for demethanization prior to mining. This technology has been developed and tested; it is now commercially available. The outburst problems in #26 Colliery, however, are quite different. They derive from the rock strata above the coal seam, and new approaches to hydrofracturing are required:

- Drillholes will be required to locate and access gas reservoirs/-outburst zones.
- Packers will be needed to withstand high differential pressures with large bore for fracturing fluid injection.
- Hydrofracturing equipment will have to be sized and packaged for handling underground.

The proposed demonstration program would be used to identify the feasibility of hydrofracturing to this particular application.

5.2 DIRECTIONAL DRILLING

5.2.1 Introduction

This section outlines the recommended drilling procedures to implement a frac within the gas bearing sandstone above the coal seam. The operational constraints are listed and the size and type of drilling equipment and accessories are recommended.

5.2.2 Constraints to Drilling

To recommend a suitable drilling program the following constraints will apply. Drill equipment, hole diameter and accessories are recommended to meet the following:

- drilling from existing underground workings
- utilize the smallest practical hole diameter
- meet flame-proof and/or intrinsic safety requirements
- provide means of shutting off hole with drill rod in place
- provide regular dip and azimuth measurements
- allow for insertion of sonde into drill string to determine rock type at or near bit during drilling
- maximize drilling rate and minimize number of rod pulls.

It is advantageous to use the smallest practical hole size to facilitate rod handling underground. Hole diameter will, however, be further constrained by the diameter of tubing to be inserted to conduct the frac and by the geometry of the bit and subassembly to allow deflection of the hole.

In order to meet operating requirements within a potentially explosive methane environment all drilling equipment, mud motors and directional equipment will be required to conform to flame-proof and/or intrinsic safety regulations. Intrinsic safety

requirements will apply, particularly to the downhole sonde for rock type determination and downhole surveying equipment.

To enhance safety during drilling, a manually operated blowout preventor, or stuffing box will be needed to control flow if high methane or water pressures are encountered. The stuffing box, in conjunction with a discharge valve can serve an alternate purpose of routing the cuttings and drilling fluid to a settling box.

Frequent dip and azimuth measurements are necessary in order to calculate the required deflection to maintain the hole above the seam. Rod pulls can be minimized by using a wireline type directional survey tool. Surveys on 15 m intervals are recommended.

Rock type is to be monitored by logging the cuttings; electric logs will have to be run at frequent intervals to coincide with directional survey measurements, so that the hole can be maintained a set distance above the coal seam. Anticipated variations in dip of the seam will make regular seam intersections necessary to locate the hole with respect to the seam.

5.2.3 Drilling Equipment

Hole Size

The hole diameter is dictated by the minimum size tubing required to perform the fracture treatment. Seamless tubing of 60 mm diameter is to be used to perform the fracture. It has an internal diameter acceptable for this demonstration, considering friction loss, pump rates and hole length. The most suitable hole diameter is 75 mm, which corresponds to NW size. Core is not

required, therefore, a full face bit can be used. Bits may be tricone, tungsten carbide drag bits or diamond, selected to suit the hardness of rock.

Mode of Drilling

Two methods of drilling are available: conventional rotary drilling and downhole motor drilling. The advantages of a downhole motor are:

- deflection is continuous, preventing 'doglegs', which are caused by using the whipstock with a conventional diamond drill
- drilling speeds are faster because the drill string does not turn and lose frictional energy against the hole, more power is transmitted to the bit with the downhole motor
- deflection is continuous. Whipstocks are a 'one shot' type device and give only 1^{o} of deflection requiring multiple use for large deflection angles. The downhole motor can be deflected up to 10^{o} per 30 m of travel in non-coring applications
- wear on the drill string is reduced because it does not turn in the hole when using the downhole motor.

The disadvantages of a downhole motor are:

- increased hourly operating cost due to rental of the downhole motor, though the unit cost per metre may be similar to conventional diamond drilling due to a faster penetration rate
- high volume of mud flow is required to power the downhole motor. Up to 6 L/s of fluid may be required to drive the downhole motor. This necessitates using a BX rod in conjunction with the NW hole size to reduce the fluid friction between the outside of the drill rod and the borehole wall. Mud pumps and sump boxes will require appropriate sizing

- tool length - the motor length for a 75 mm diameter hole is 5 m and requires a drilling set-up to accommodate the one-piece motor.

Due mainly to the ease of deflection, the downhole motor is the recommended method of drilling. Characteristics are shown in Figures 5-1, 5-2 and 5-3 for the Norton Christensen Mach 2 drill with an outside diameter of 60 mm. Additional characteristics for the drill are listed below:

Tool Outside Diameter	60 mm
Hole Size	73 mm - 89 mm
Approximate Torque	136Nm
Maximum Horsepower	18 kW
Maximum Efficiency	75%
Thread Connection	BW Rod
Weight	95 kg
Length	4572 mm

Deflection Shoe and Stabilizers

Deflection of the downhole motor is enabled by a spring loaded deflection shoe (Figure 5-4). The shoe acts as an eccentric stabilizer which forces the downhole motor off centre at the bit end, thereby causing the bit to deflect from the axis of the existing hole. The amount of deflection is controlled by one or more of 'Belville' type springs inserted into the shoe and is dependent on formation hardness. In certain cases an additional shoe can be attached at the rod end of the downhole motor and oriented 180° from the other deflection shoe to provide additional deflection force. In small hole diameters of the nature presented here, deflections in the order of 8° to 10° per 30 m of hole can be achieved, however, this may be reduced to 5° per 30 m to allow passage of a wireline core barrel. The direction of deflection may be changed by turning and locking the drill rod in the desired position from the collar.

Straight lengths of borehole may be drilled by pulling the rod and replacing the deflection shoe with concentric stabilizers.

Directional Surveys

Hole orientation can be monitored regularly during drilling using a Wireline 'One Shot' Eastman Whipstock Camera (Type E). This camera utilizes a magnetic compass to indicate azimuth and, therefore, must be used in conjunction with 6 m to 9 m of non-magnetic drill rod (Beryllium) to prevent distortion of the magnetic field. The camera would be positioned with an orientating sub located on the rod end of the downhole motor.

Downhole Sonde

A wire line gamma detector sonde may be used to differentiate between coal, sandstone and shale. Since the logging will take place through the drill rods, a calibration test will be required to determine the gamma count rate through a known section of strata. This procedure can be completed by drilling a short, fully cored hole through strata at several different intersection angles, followed by subsequent gamma logging. This method has been tested in the UK and found to be successful.

5.2.4 Demonstration Program

A recommendation for the drilling program associated with a hydrofracturing demonstration is outlined below. It is assumed that this demonstration will take place in one of the CBDC mines on Cape Breton Island. The following assumptions are made:

- drilling could take place from arched roadway with axis of drillhole along axis of roadway

- the seam would be located along the bottom of the arched roadway, allowing drilling from rock
- 3.8 m x 5.5 m arches are used in roadway
- hydraulic power is supplied on site for drill and mud pump.

The proposed plan and section layout of the equipment is shown in Figure 5-5 including the layout of the proposed drillhole with respect to the coal seam. The aim is to direct the borehole down dip approximately 3 m to 10 m above the seam. To determine any variation in clearance between borehole and top of seam, the borehole would be directed downwards every 50 m until the seam is detected, using both drill cuttings and the gamma ray sonde. At this point, the bit, motor and rods would be pulled and the borehole grouted from bottom of hole to the point immediately before the last deflection. The seam dip would then be calculated and the borehole declination would be corrected to maintain the required clearance above the seam.

The above procedure would be repeated every 50 m until 400 m of hole is completed or until a sand channel is intersected as indicated by cuttings and downhole gamma ray surveys.

If a sand channel is intersected, then the drill rods would be pulled and the appropriate packers set with tubing to perform the frac. The methane liberated by hydrofracturing would be drained through the stuffing box and safety valve into an existing methane range. A vacuum pump could be used to increase methane flow.

5.3 PACKERS

Packer selection is a major consideration in performing a frac. Most prior work in fracturing coal seams has taken place from vertically drilled wells with hole diameters of greater than 100 mm. Internal diameters in these packers are of sufficient size to allow over 1 m^3/min

flow of fracturing fluid. The proposed use of 75 mm diameter holes for an underground demonstration program dictates the use of smaller packers and thus smaller internal diameters (see Figure 5-6 for packer terminology).

Packer data, suitable for use in slim holes is listed in Table 5-1. Since the frac is to be designed at a pressure of 27.6 MPa (Figure 5-7) a minimum packer element outside diameter of 60 mm would be required. This particular packer has an internal diameter of 19.1 mm which will account for an estimated pressure drop of 40 kPa. Since the total anticipated pressure drop through the tubing is estimated to be 3.2 kPa/m, the pressure drop through the packer will be comparatively small with respect to that through the tubing.

It is recommended that the packer be of a recoverable type, as the individual packer cost is in the order of $3500 each. The use of replaceable elements on the packers is recommended as wear of the element in the horizontal borehole is anticipated to be high due to friction.

Straddle packers, comprising two connected packers between which the frac is introduced into the formation, would be convenient. This feature would allow isolation of the frac to the straddle interval. This type of packer may not be feasible, however, as the internal complexity of the packer design restricts the mandrel diameters to the point where pressure loss would become too large to perform the fracture treatment at an acceptable pumping rate.

5.4 HYDROFRACTURING EQUIPMENT

The actual equipment to perform the hydrofracture consists of:

- high pressure pump

- sand mixing unit
- water tank.

The above equipment is required to perform the following duty specification:

• volume of water	6.3 m^3
• weight of sand	2 t
• pumping rate	0.64 m^3/min
• estimated fracing pressure	24 MPa
• estimated pump pressure	28 MPa
• sand/water mixture	960 kg/m^3

5.4.1 Pumping

In order to meet the above specification an SA-644-5 well service pump is recommended for pumping the sand/water mixture. The specification sheet for the SA-644-5 pump is shown in Figure 5-8. This pump has a maximum pumping capacity of 31700 kPa at 0.7 m^3/min which provides excess capacity. Estimated power to pump the fracture treatment is 300 kW.

The pump would be skid mounted for use underground and an acceptable power supply (electric or hydraulic) would be provided.

5.4.2 Sand Mixing

The sand/water mixture could be mixed in an SAS-63 slurry averaging system (Figure 5-9). This unit, which was developed to mix cement slurries allows for manual loading of the sand and contains a densometer for accurate determination of sand/water ratio. It is proposed that the slurry be continually mixed during the fracturing operation.

Although this unit does not pump the mixture down the hole, a 75 kW drive is required to power the mixing pump and to activate pressure operated check valves for feeding to the high pressure pump. The slurry averaging system is mounted with diesel engines for use on surface. These drives will be replaced with flame-proof or hydraulic motors for use underground.

5.4.3 Tankage

Since the fracture treatment will be pumped at a rate of 0.7 m^3/min all water for the frac will be required at the pumping site prior to pumping. In addition, the water is to be gelled to enhance sand transportation characteristics. For these reasons an 8 m^3 water storage tank (or series of tanks) is required at the frac site. As the ambient temperature underground is not expected to be less than 10°C no preheating of the gel is required, as is normal practice in the petroleum industry. Inflatable bladders may be used as an alternative to metal tanks, to satisfy space constraints.

5.5 DISCUSSION

The drilling program associated with the hydrofracturing demonstration will serve two purposes: exploration and access to the formation to be fractured. Due to the location of the coal measures under the sea, very few vertical holes have been drilled from seabed which results in poor deliniation of the coal seam structure and few intersections with the paleo-sandstone channels. For this reason, horizontal holes drilled from underground are to be used to locate the sandstone channels, and wher. intersected, for fracturing.

Sequencing of the drilling and hydrofracturing program will be determined when the channels are intersected. It is proposed that the

drillhole be turned down to intersect the coal at regular intervals. However, if a sandstone channel is intersected, then the relative position with respect to the coal seam should be calculated and in situ testing for pore pressure undertaken to determine the outburst potential. If a hydrofracturing treatment is undertaken, then no further drilling will be done from that hole, as it will be used exclusively for methane drainage.

To locate channels further down dip from hydrofracture treatments, it will be necessary to re-collar a second hole. As the lithology will be known from the first hole, it will not be necessary to deflect down to the coal seam until virgin lithology is reached past the existing fracture. Using this technique, a separate hole will be required for any fracture. Use of straddle packers may, however, obviate the multi-hole equipment by containing the treatment to selected segments, depending on packer spacing if more than one channel is located. Unfortunately, the internal diameter of straddle packers is too small to achieve anticipated pumping rates.

TABLE 5-1
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SPECIFICTION FOR SLIMHOLE INJECTION PACKERS

(After: Lynes United Services 1984)

Element OD (mm)	Element Length (mm)	Mandrel Bore (mm)	Seal Length (mm)	Tool Length (mm)	For Calipered Open Hole or Casing Sizes (mm)
36.5	431.8	11.7	152.4	1016.0	48.3
	914.4		635.0	1498.6	41.3-63.5
41.3	431.8		152.4	1016.0	52.4
	1219.2		914.4	1803.4	44.5-63.5
44.5	431.8	11.7	152.4	1016.0	60.3
	1219.2		914.4	1803.4	47.6-63.5
47.6	431.8		152.4	1016.0	60.3
	1219.2		914.4	1803.4	50.8-69.9
54.0	584.2	19.1	304.8	1193.8	73.0
	1219.2		914.4	1828.8	57.2-88.9
57.2	584.2		304.8	1193.8	73.0
	1219.2		914.4	1828.8	63.5-95.3
66.7	584.2	19.1	304.8	1193.8	88.9
	1219.2		914.4	1828.8	76.2-114.3
69.9	584.2		304.8	1193.8	88.9-101.6
	1219.2		914.4	1828.8	88.9-120.7

FIGURE 5-1
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

TORQUE - PRESSURE DROP CURVE FOR DOWNHOLE MOTOR
(Mach 2, Norton Christensen Inc.)

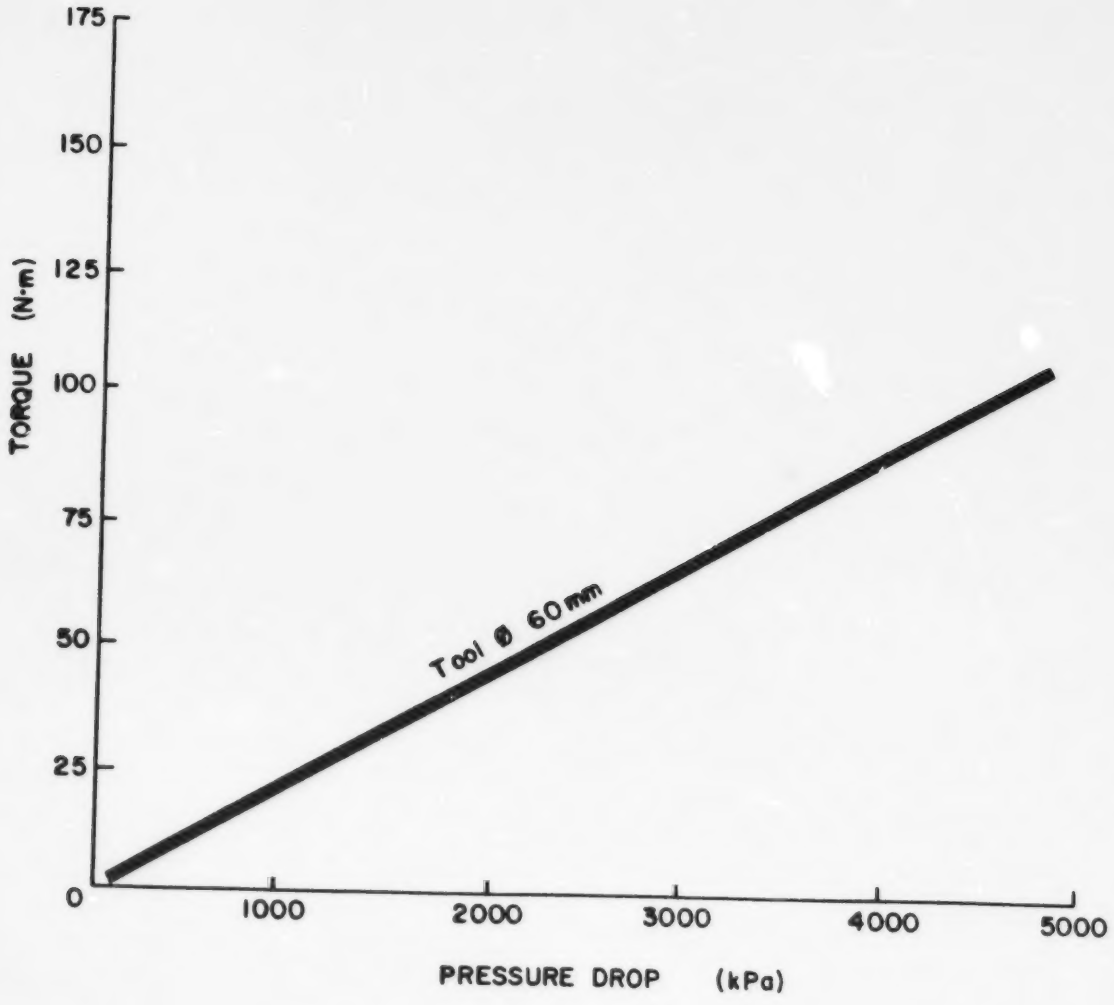


FIGURE 5-2

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

FLUID FLOWRATE CURVE FOR DOWNHOLE MOTOR

(Mach 2, Norton Christensen Inc.)

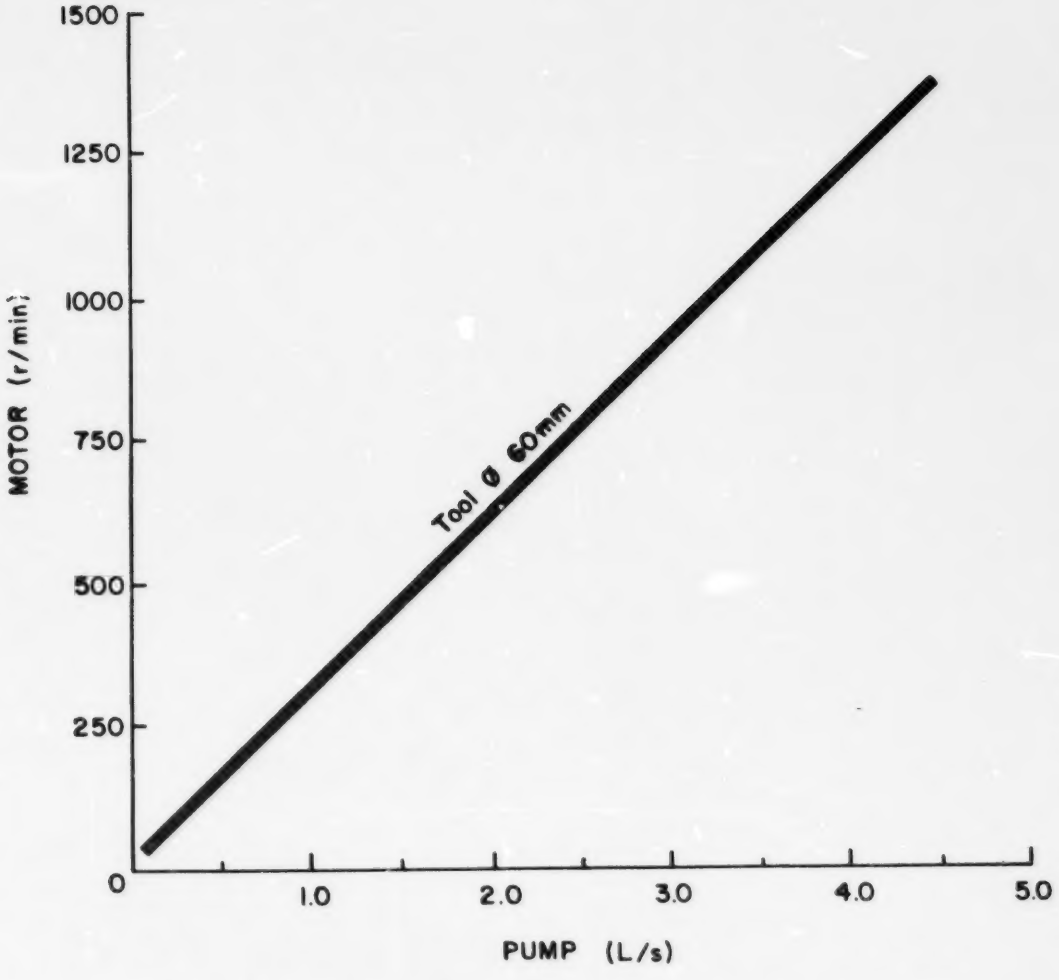


FIGURE 5-3
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

POWER CURVE FOR DOWNHOLE MOTOR
(Mach 2, Norton Christensen Inc.)

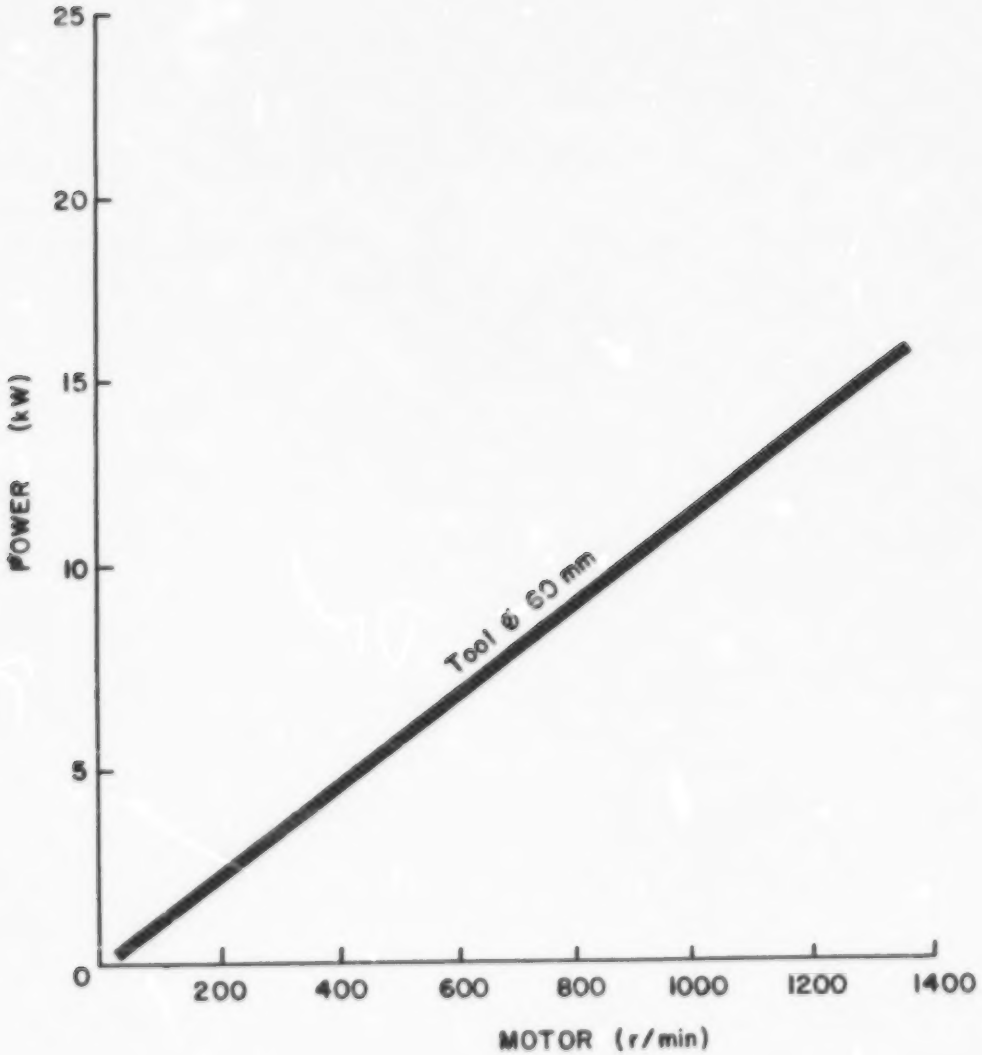
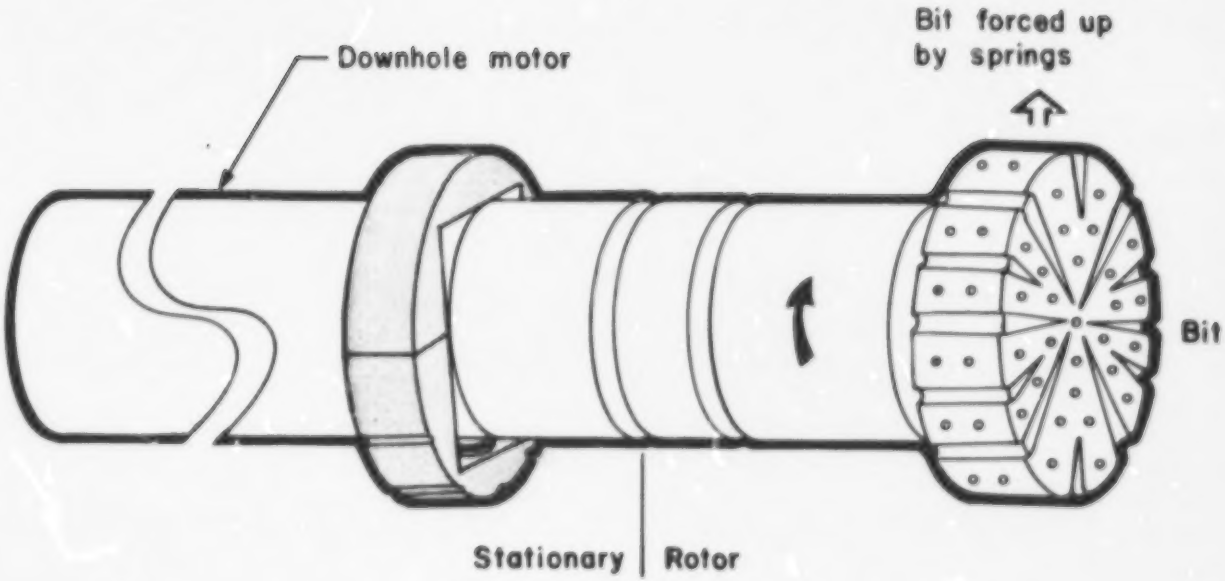
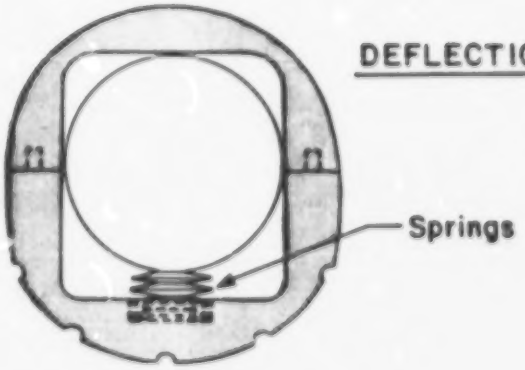


FIGURE 5-4
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

DOWNHOLE MOTOR WITH DEFLECTION SHOE





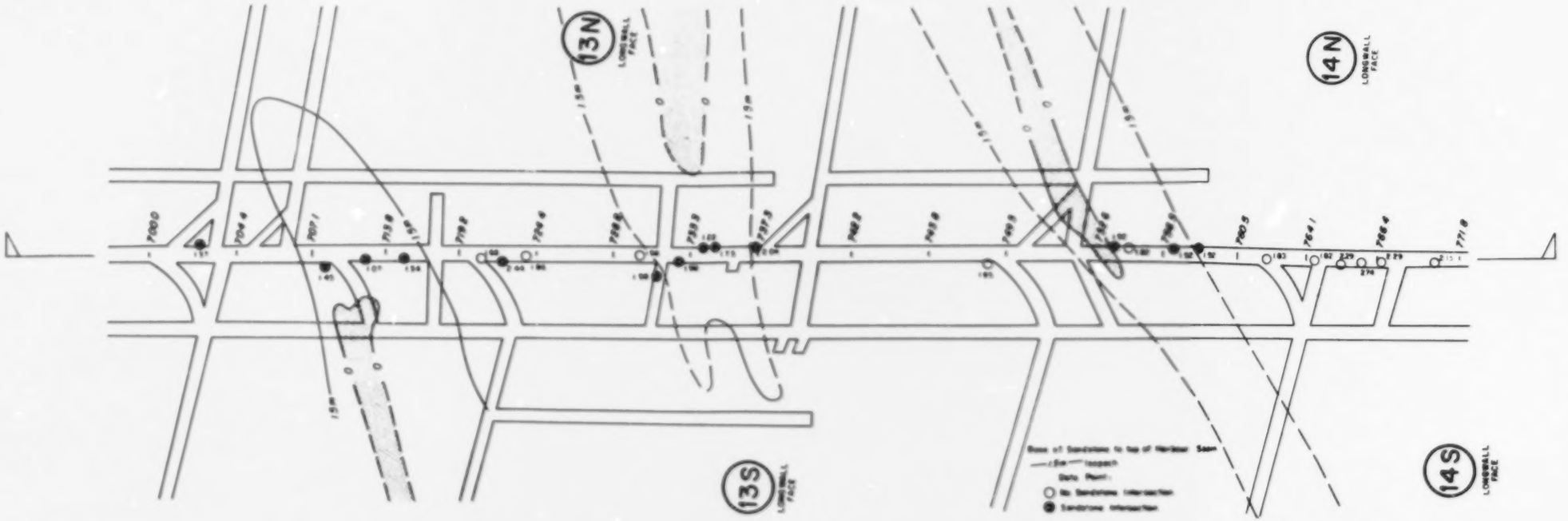

13N
LONGWALL FACE
14N
LONGWALL FACE
13S
LONGWALL FACE
14S
LONGWALL FACE
7000
7040
7091
7138
7211
7278
7324
7368
7433
7373
7403
7438
7463
7503
7541
7586
7711
150m
150m
150m

FIGURE 5-6

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

TYPICAL OPEN HOLE INJECTION PACKER

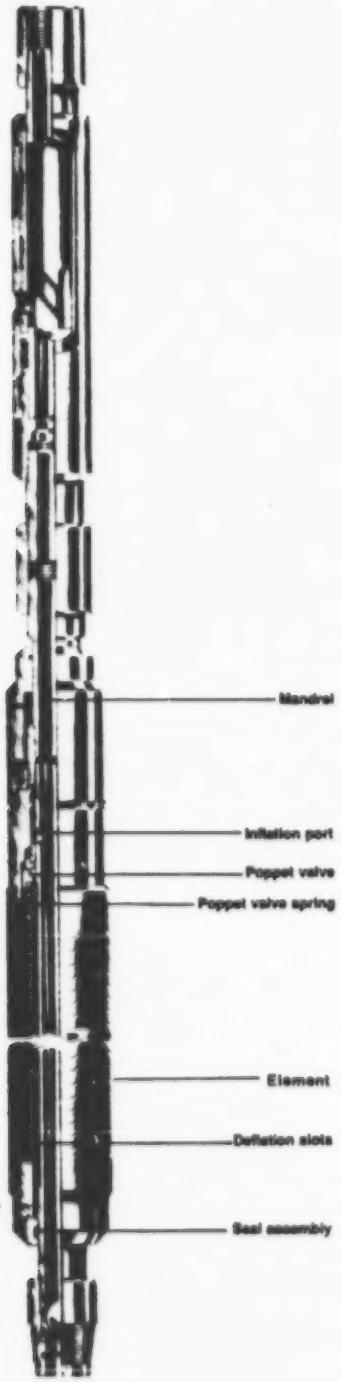
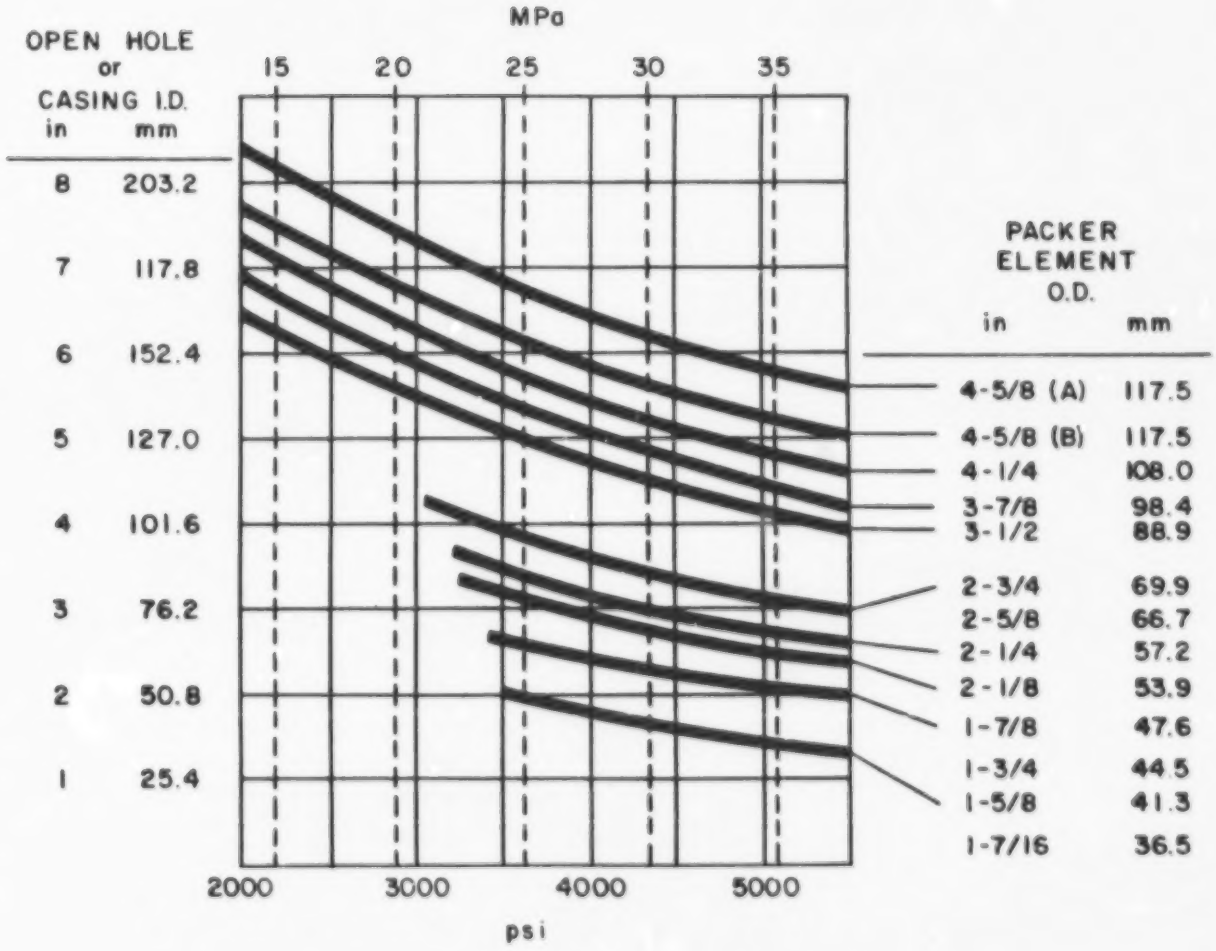


FIGURE 5-7

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

LIMITING DIFFERENTIAL PRESSURE FOR VARIOUS PACKERS

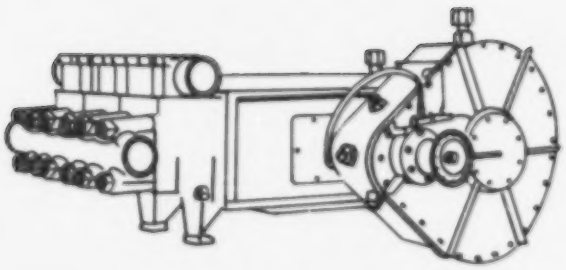
(Lyons United Services Ltd.)



LIMITING DIFFERENTIAL PRESSURE

FIGURE 5-8
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

DATA SHEET: HIGH PRESSURE PUMP
(Nowsco SA-644-5)



Specifications

Pump Size
(Max. Plunger Dia. x Stroke) ..... 114 mm x 152 mm
4½ in. x 6 in.
Standard Plunger Sizes ..... 114 mm
4½ in.
Rated KW 373
HHP 500
Maximum Working Pressure:
Discharge ..... 41369 kPa
6000 psi
Suction ..... 1034 kPa
150 psi
Gear Ratio (Standard) 5.45:1
Oil Capacity ..... Dry Sump

Performance Data — Intermittent Service (Metric)
Stroke Lgth. 152 mm ... Max. Pressure 41369 kPa (.4692 m³/min) ... Max. Vol. 2.111 m³/min (10597 kPa) ... Max. Speed 450 r/min
(Volumes indicated are Displacement of Noncompressible Fluid)

Plgr. Dia. mm	Plgr. Area cm²	Displacement L/rev.	Max. Pressure kPa	100 r/min		150 r/min		200 r/min		250 r/min		300 r/min		350 r/min		400 r/min		450 r/min	
				kPa	m³/min	kPa	m³/min	kPa	m³/min	kPa	m³/min	kPa	m³/min	kPa	m³/min	kPa	m³/min	kPa	m³/min
114	102.606	4.6913	41369	41369	.4692	31785	.7037	23842	.9382	19071	1.173	15892	1.407	13624	1.642	11921	1.877	10597	2.111
Gear Unit Pinion Shaft r/min at Gear Ratio of:			5.45:1	545		817		1090		1362		1635		1907		2180		2452	
Kilowatt-Hydraulic				313		373		373		373		373		373		373		373	

Important: Please note that these ratings are for intermittent service.
Operations at these maximum conditions should not exceed a total of 3 hours in any 24 hour period.
Maximum Plunger load dependent on conditions and applications.

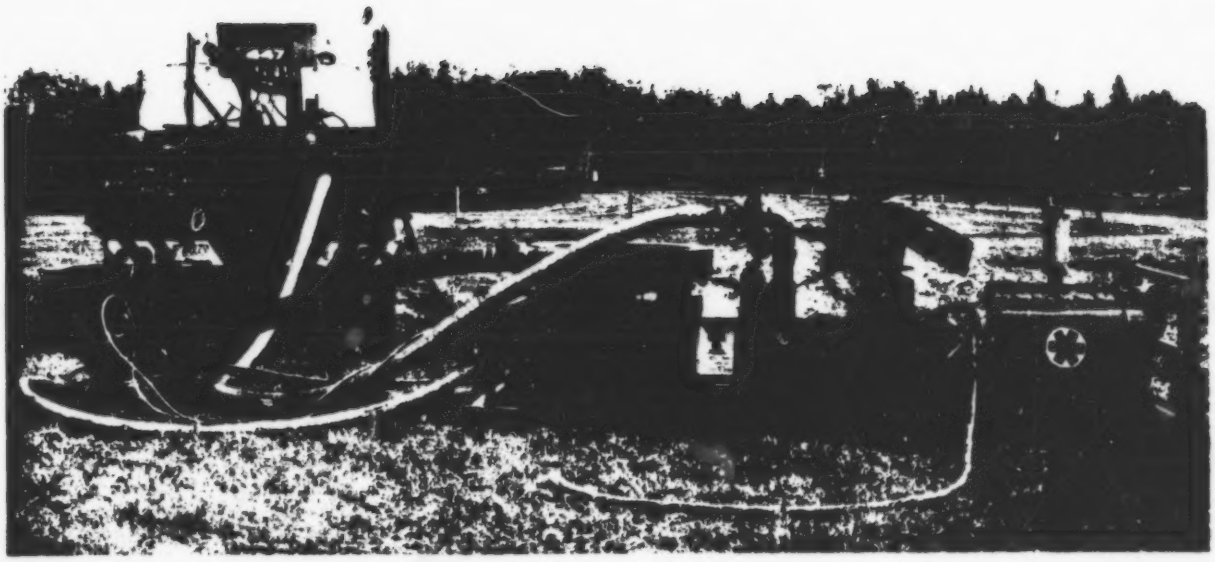
Plunger Diameter (mm)	Stuffing Box Bore (mm)
114	140

FIGURE 5-9

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

DATA SHEET: SLURRY AVERAGING SYSTEM

(Nowsco SAS-63)



DIMENSIONS AND SPECIFICATIONS

Width	— 2.13 m (8 ft.)
Length	— 4.88 m (16 ft.)
Weight	— 1820 kg (4,013 lb.)

EQUIPMENT SPECIFICATIONS

Motor ✱	— 4 (or 6) cylinder Deutz diesel or (3 or 4) cylinder GM diesel
Mixing Pump	— Mission 50.8 mm x 76.2 mm (2 in. x 3 in.) centrifugal
Suction Pressurizer Pump	— Mission Magnum 101.6 mm x 127.0 mm (4 in. x 5 in.) centrifugal
Mixing Capacity	— 3.2 m³/min (20 bpm)
Volume Capacity of Mixing Tank	— .5 m³ (3 bbl)
Discharge Capacity	— 1.5 m³/min (9 bpm) slurry

✱ Diesel engine shown to be replaced with permissible motor.

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION 6 - RESEARCH AND DEVELOPMENT NEEDS FOR DEMONSTRATION

Table of Contents

		Page
6.1	Introduction	6-1
6.2	Geotechnical Considerations	6-1
6.2.1	Stress Determination	6-2
6.2.2	Reservoir Characteristics	6-4
6.2.3	Rockmass Characteristics	6-5
6.3	Equipment Design and Modification	6-5
6.3.1	Directional Drilling	6-5
6.3.2	Hydrofracturing	6-6
6.4	Operational Considerations	6-7
6.5	General Testing	6-7
6.6	Discussion	6-8

FIGURE
(Following Text)

6-1 Idealized Pressure-Time Curves for a 'Tight' Reservoir Rock

SECTION 6 - RESEARCH AND DEVELOPMENT NEEDS FOR DEMONSTRATION

6.1 INTRODUCTION

Hydrofracturing is a proven technology used to enhance fluid flow from petroleum reservoirs and from coal seams. The application of this technique for the control of rock/gas outbursts requires substantial research and development prior to a demonstration in the Sydney coalfield. The research and development program can be broadly divided into geotechnical considerations, equipment modifications and operational considerations.

6.2 GEOTECHNICAL CONSIDERATIONS

Sophisticated computer models have been developed to design hydraulic fracturing treatment programs for oil and gas reservoir stimulation and methane production from coal seams. These models can be applied to the hydrofracturing treatment design for outburst control, if the critical relationships between stress, pore pressure, permeability and strength for outburst conditions in a given rockmass, can be resolved. The problem, although difficult, is not insurmountable. A considerable empirical data base has been established from the outbursts in the now closed No.26 Colliery. Outbursts have been confined to:

- channel sandstone units in close proximity to the coal seam (to date in the roof only)
- single entry drivages in virgin ground
- depth below sealevel greater than 700 m
- initiation by blasting (with one exception)

The channel sandstones in the Lingan (Harbour) Mine, currently the deepest workings in the Sydney Coalfield, need to be investigated to establish:

- state of stress
- rockmass characteristics
- gas reservoir properties.

6.2.1 Stress Determination

A basic requirement is a clear understanding of the state of stress in the rockmass prone to outbursts. This includes the virgin stress and the induced stress due to mining activity.

Virgin Stress is the controlling factor for hydrofracture orientation and is the background stress level upon which the mining stresses are superimposed. This triaxial stress field is commonly determined from strain relief measurements on core specimens assuming elastic behaviour. A stress tensor can be calculated from a single overcore using the CSIRO triaxial strain cell, or from overcores in three non-parallel drillholes, using biaxial cells such as the 'doorstopper' or the USBM deformation gauge. The three drillholes should be oriented perpendicular to each other and converge into a block of homogenous lithology. Since virgin stress is the target, measurements should be at least three roadway diameters away from any mine workings.

Hydraulic fracturing, unlike other methods of in situ stress determination, does not require an extensive knowledge of mechanical properties of the rockmass under study. Hydrofracturing in its simplest form consists of sealing off a section of a drillhole and injecting fluid into this section until the pressure is sufficient to create a fracture. The fracture is extended by

continued injection of the fracturing fluid. In situ stresses are determined on the assumption that the stresses acting at the borehole can be determined from the breakdown and shut-in pressures, and a knowledge of the rock's tensile strength. The pressure history (Figure 6-1) of pumping during an hydraulic fracturing test is related to the in situ stresses through the relationship (Hubbert and Willis, 1957):

$$P_b = 3S_{min} - S_{max} - P_o + T \quad (1)$$

where:

- P_b - Breakdown pressure
- S_{max}, S_{min} - Maximum and minimum principal stresses acting perpendicularly to the borehole axis
- T - Rock's tensile strength
- P_o - Fluid pore pressure

and

$$S_{min} = P_s \quad (2)$$

where

- P_s - shut-in pressure

A clear breakdown pressure is not always observed, and it is not always possible to accurately determine the tensile strength of the rock. An alternative approach to determining the in situ stresses is based on the reopening pressure "P_{ro}", defined as the pressure required to open a closed crack on subsequent pumping cycles. Equation (1) can then be replaced by:

$$P_{ro} = 3S_{min} - S_{max} - P_o \quad (3)$$

after Bredehoeft et al., (1976). Equation (2) is necessary to recover both S_{min} and S_{max}.

In the derivation of Equations (1), (2) and (3) it has been assumed that one of the principal stresses is parallel to the borehole. For this case, the problem reduces to the two-dimensional plane strain situation of a circular hole in an infinite plane. Inclined boreholes, such as those used for testing in mines and underground excavations, are unlikely to be aligned with the principal stresses (Daneshy, 1973). It would be advantageous to align the drillholes parallel to the predetermined minimum stress direction.

Fracture geometry/containment in the reservoir is dependent on the stress in the bounding strata (i.e. coal and mudstone). Stress determination must be made in these strata.

Mining induced stress is the stress state near mine openings. Where the outbursts have occurred. It is essential to understand the reorientation of the stress tensor due to mining operations. Stress meters (e.g., vibrating wire stress meter) can be installed ahead of mining to monitor the change in the stress tensor.

6.2.2 Reservoir Characteristics

The sandstone units in the outburst areas are gas reservoirs. In order to reduce the risk of outbursts, the pore pressure must be reduced by producing methane from the sandstone reservoir.

Porosity and pore pressure define the quantity of gas present and need to be determined. Permeability defines the fluid flow potential within the reservoir; this is influenced by the water saturation. All of these parameters should be determined for currently accessible sandstone reservoirs in order to define the gas drainage potential by hydrofracturing.

6.2.3 Rockmass Characteristics

The geometry of the channel sandstone units must be determined. The documentation of the channels in No.26 Colliery (Figure 5-5) was insufficient since neither the thickness nor the downdip continuity had been determined.

Rock strengths for various pore pressures and loading rates will have to be determined for a number of sandstone reservoirs. This information will be required to assess an acceptable pore pressure after methane production from a fractured reservoir.

6.3 EQUIPMENT DESIGN AND MODIFICATION

Since the drilling and hydrofracturing demonstration program will be carried out from underground, there will be special requirements for the equipment, notably permissibility, space and weight constraints. Some variables such as rock strength, drilling speed and bit type will not be known until the demonstration program is started. These items are addressed in the Section 6.4 on operational considerations.

6.3.1 Directional Drilling

The directional drilling program will be required to locate the paleo-sandstone channels and to access them for hydrofracturing.

Drilling equipment such as the drill, mudpump, wireline hoist and auxiliary equipment such as downhole logging and surveying tools, are not permissible for use in an underground coal mine. This impediment may be overcome by replacing the present rotary drives or power supplies with those that are permissible. In the case of power drives, flameproof electric motors or hydraulic

motors driven from existing power packs may be used. Intrinsic safety certification may be required for the instrumentation.

6.3.2 Hydrofracturing

As with the drilling equipment, hydrofracturing pumps and mixers are currently only available in a non-permissible format. These will require the retrofitting of permissible drives and power supplies. In addition, to satisfy space and weight constraints underground, this equipment will require skid mounting and may require breaking down into modular components. Monitoring instrumentation will be required during the hydrofracturing portion of the demonstration program to measure pressure and flow rates both before and after the fracture has been completed. Proppant concentration during mixing will be monitored with a densometer. Monitoring must include gas production before and after stimulating the reservoir.

Modifications or redesign of commercially available straddle packers for use in a 75 mm diameter hole, to allow injection rates up to 0.7 m^3/min would be advantageous. If the straddle packer were used to perform multiple fractures from a single collar location, then drilling costs could be reduced. The use of a single element packer would allow only one fracture per collar setup and would not allow precise placement of the fracture interval in the borehole.

Water storage tanks will have to be built (dependent on underground space limitations). Calculations based on the fracture program recommended in Section 4 show that 8 m^3 of tankage will be required. The gel will be added and mixed in these tanks.

AMCL

The first step prior to the initiation of the above recommendations is to check all underground clearances and weight restrictions on the underground transport system. In addition, the collar location must be selected prior to equipment modification so that it is known which mine services will be available.

6.4 OPERATIONAL CONSIDERATIONS

There are many unknown variables which will directly affect the demonstration program and will not be determined until the program is started. It is not known what type of bit is suitable for drilling this rock with the directional drill. Drill fluid cannot be recommended at this time either, as the caving characteristics of a horizontal hole in the roof strata are unknown. It is expected that several types of bits (diamond, tricone, drag, etc.) will have to be tried to optimize drilling speed.

Settling rates for drill cuttings are expected to directly affect the design, mainly volume, of settling tanks. The volume of these tanks is determined as a function of drilling fluid viscosity and density cuttings size, and borehole volume.

The fracture orientation is an unknown at present. If the fracture is parallel to the axis of the borehole, then fracing fluid will likely bypass the packer, resulting in failure. If this happens, then multiple packers may have to be used to maintain the fracture pressure.

6.5 GENERAL TESTING

Outlined below are recommendations for testing prior to initiation of a demonstration program.

Gel Tests

Since the water used for hydrofracturing will require gelling prior to mixing with proppant, a gel test with a sample of mine water should be undertaken. Tests will indicate if additives are required to enhance gelling characteristics.

Sonde Calibration

Most natural gamma and density gamma borehole measurements are made in vertical holes intersecting nearly horizontal strata. This geometry allows ready identificaton of coal/rock boundaries due to the abrupt change in detector counting rates as it passes the formation interface at right angles. The proposed demonstration program will involve logging holes parallel to bedding planes. Under these conditions it is anticipated that the differential count rate as the tool passes through an interface will not have sufficient resolution to positively locate the rock boundary. It is recommended that the sondes be calibrated in short horizontal holes through the formation, at several bedding intersection angles. This calibration program should be carried out in identical formations so that absolute count rate values can be used to determine proximity to adjacent formations.

6.6 DISCUSSION

The recommendations for continued development and research are directed at three main areas: geotechnical testing, equipment modifications and operational considerations.

As addressed earlier, the gas reservoir to be fractured has certain geotechnical characteristics which combined, may lead to outburst

conditions, notably: stress, rock strength, pore pressure and permeability. It is important to measure each of these variables accurately, preferably in the in situ environment, to assist in optimizing the hydrofracturing program, so pore pressures can be reduced to 'safe' limits in a minimum of time.

Equipment and techniques for the proposed demonstration drilling and hydrofracturing program are currently available. The initiation of a demonstration program is **not** contingent on development of new pieces of equipment. However, minor modifications, mainly for drives, are required to make the equipment permissible for use in coal mines in Nova Scotia. A check list of items to be considered for setting up a demonstration hydrofracturing program is shown in Table 6-1.

Development of new equipment (i.e., straddle packers) may only be necessary for cost reduction on 'production scale' hydrofracturing projects. Major equipment modifications or design are not recommended until equipment enhancements are identified in the demonstration program.

The hydraulic fracturing demonstration site and drillhole direction must be carefully chosen to assure that the actual fracturing site will be intersected by future mine roadways. Valuable information on crack width, orientation and sand distribution would be gained. This would give feedback on the accuracy of the simulator and allow adjustments to enhance future simulations.

TABLE 6-1
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

DEMONSTRATION PROGRAM CHECK LIST

Items for consideration in the planning of a preliminary test demonstration are listed as follows:

1. In the undersea workings aim to identify the location of channel sandstones as a target area.

2. Determine the formation parameters as shown in Table 4-1.

3. Select a roadway with a shale or sandstone exposed near the roof to collar drillhole.

4. Mine services to include:

   - men and materials transport
   - good ventilation
   - electricity supply
   - water supply
   - methane pipe range.

5. Arrange for drilling equipment for near horizontal drillhole with a diameter in the order of 75 mm. The equipment to include:

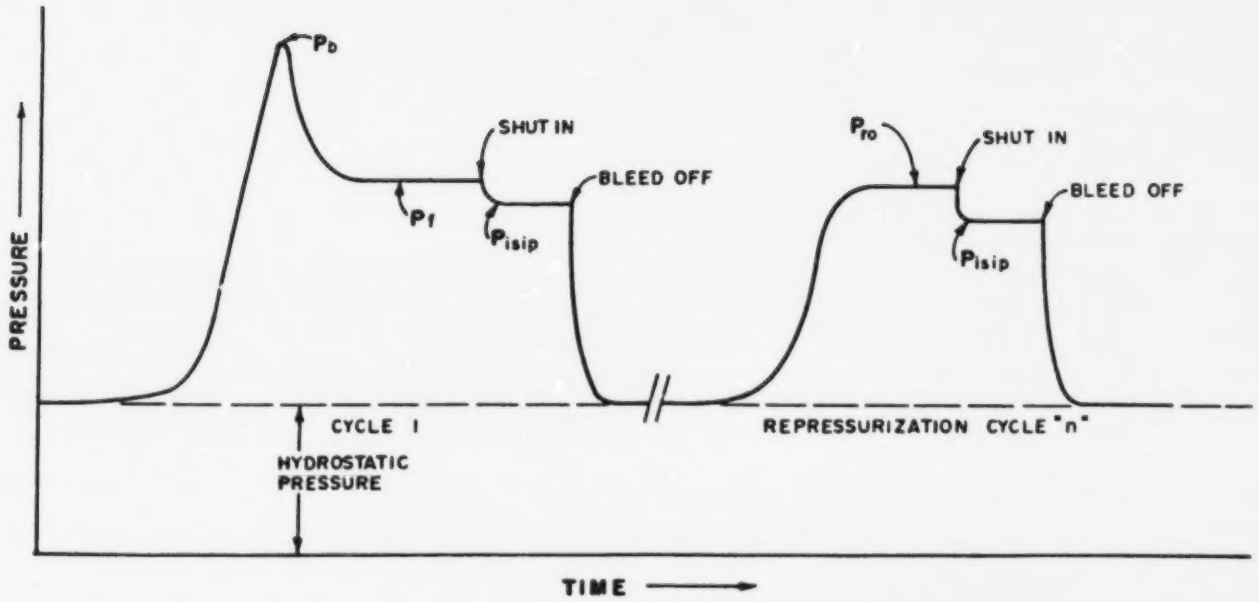
   - permissible motor
   - initial length of casing to form collar of drillhole
   - stuffing box and valves compatible with drill and casing
   - drill motor - preferably downhole directional (Section 5.2.3) complete with deflection shoe and stabilizers
   - drill rods with wire-line survey equipment and downhole sondes
   - two downhole packers as described in Section 5.3
   - mud pumping equipment capable of 6 L/s complete with settling tanks for drilling mud recirculation
   - cementation equipment
   - assemble and commission on surface before taking underground.

6. Arrange for hydrofracturing equipment of a type similar to that outlined in Section 5.4. The equipment to include:

   - permissible motors
   - high pressure pump
   - sand mixing unit
   - water tank
   - assemble and commission on surface before taking underground.

FIGURE 6-1
HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

IDEALIZED PRESSURE-TIME CURVES FOR A 'TIGHT' RESERVOIR ROCK



LEGEND

P_b BREAKDOWN PRESSURE

P_f FRACTURE EXTENSION PRESSURE

P_{isip} INSTANTANEOUS SHUT-IN PRESSURE

P_{ro} FRACTURE REOPENING PRESSURE

GEOTECH

AMCL

HYDROFRACTURING FOR PREVENTION OF ROCK/GAS OUTBURSTS

SECTION 7 - BIBLIOGRAPHY

Table of Contents

		Page
7.1	References Cited	7-1
7.2	Selected Bibliography	7-5

SECTION 7 - BIBLIOGRAPHY

7.1 REFERENCES CITED

Abou-Sayed, A.S.; Brechtel, C.E. and Clifton R.J.
1978: In Situ Stress Determination by Hydrofracturing: A Fracture Mechanics Report
J. of Geophys. Res., v.83/36, pp 2851-2862.

Abou-Sayed, A.S.; Jones, A.H. and Simonson, E.R.
1977: On the Stimulation of Geothermal Reservoirs by Downward Hydraulic Fracturing
Paper No.77-Pet-81, ASME Energy Tech. Conf. & Exhib., Houston, TX, Sept.

Allen, T.O. and Roberts, A.P.
1982: Production Operation, v.1. (2nd ed.)
Oil and Gas Consultants, Tulsa, OK.

Ancell, K.L. and Stevenson, J.W.
1979: Degasification Parameters and Well Completion Procedures for the Mary Lee/Blue Creek Coalbeds in Tuscaloosa, Alabama.
Proc. of 2nd Ann. Methane Recovery from Coalbeds Symp., Morgantown Energy Tech. Centre Rep. METC/SP-79/9, (Apr.)

Aston, T. and Cain, P.
1985: Gas and Rock Outbursts at No.26 Colliery, Sydney Coalfield, Nova Scotia - A Case History
Manuscript for presentation, 21st Int. Conf. Safety in Mines Res. Inst., Oct. 1985, Sydney, NSW, Australia; 7 p.

Bauer, A.; Calder, P.N.; Crosby, W.A. and Workman, L.
1981: Drilling and Blasting in Open Pits and Quarries, Part 1
Queen's University, Kingston. Section C, pp 2-7.

Bredehoeft, J.D.; Wolff, R.F.; Keys, W.S. and Shutter, E.
1976: Hydraulic Fracturing to Determine the Regional in situ Stress, Piceance Basin, Colorado
Geol. Soc. Am. Bull. v.87, p. 250-258.

Cervik, J.
1981: Methane Control Technology During Mining
Reprint 81-46, AIME Ann. Mtg., Chicago, IL, Feb. 22-26.

Cleary, M.P.
1978: Primary Factors Governing Hydraulic Fractures in Heterogeneous Stratified Porous Formations
Paper No.78-Pet-47, ASME Energy Tech. Conf. & Exhib., Houston, TX, Nov.

Clifton, R.J.
1974: Some Thoughts on Crack Growth in Hydraulic Fracturing
Terra Tek Report TR 76-82, Oct.

Cook, T.A. and Erdogan, F.
1972: Stress in Bonded Materials With a Crack Perpendicular to the Interface
Int. J. Eng. Sci. 10, pp 677-697.

Cooke, Jr., C.E.; Gidley, J.L. and Mutti, D.H.
1977: Use of High-Strength Proppant for Fracturing Deep Wells
SPE Paper No.6440, Deep Drilling and Production Symp., Amarillo, TX, Apr.

Cutler, R.A.; Jones, A.H. and Swanson, S.R.
1981: New Proppants for Deep Gas Well Stimulation
Paper No. SPE 9869, Low Permeability Gas Reservoirs Symp., Denver, Co., May.

Daneshy, A.A.
1971: True and Apparent Direction of Hydraulic Fractures
Soc. of Pet. Eng. Jour., v.12, pp 149-163.

1973: A Study of Inclined Hydraulic Fractures
Soc. of Pet. Eng. Jour., v.14, pp 61-68.

Ely, F.
1981: Fracturing Fluid Systems: State of the Art
Proc. of 28th Ann. Mtg., Southwestern Pet. Short Course, Texas Tech. University, Lubbock, TX, Apr.

Geertsma, J. and de Klerk, F.
1969: A Rapid Method of Predicting Width and Extent of Hydraulically Induced Fractures
J. Pet. Tech. SPE-AIME, Dec. pp 1571-1581.

Golder Associates
1984: In Situ Stresses Determination in No.26 Colliery, Cape Breton, Nova Scotia
Report to CANMET, Golder Associates Report No.831-1296, Feb.

AMCL

Hanson, M.E.; Anderson, G.D. and Shaffer, R.J.
1980: Effects of Various Parameters on Hydraulic Fracturing Geometry
Paper No.SPE 8942, Unconventional Gas Recovery Symp., Pittsburgh, PA, May.

Hubbert, M.K. and Willis, D.G.
1957: Mechanics of Hydraulic Fracturing
Trans. of SPE of AIME, v.210, pp 153-168.

Jones, A.H.
1984: Methane Production Characteristics of a Deeply Buried Coalbed Reservoir
Draft of Final Report (Feb. 1983 - Sept. 1984). Prepared for Gas Research Inst., Contract No.5081-214-0577, Sept.

Lambert, S.W.; Trevits, M.A. and Steidl, P.F.
1980a: The Feasibility of No-Proppant Stimulation to Enhance Removal of Methane from the Mary Lee Coalbed
US Dept. of Energy Rep. DOE/CMTC/TR-80/1. Apr.

1980b: Vertical Borehole Design and Completion Practices to Remove Methane Gas from Mineable Coalbeds
U.S. Dept. Energy Rep. No.DOE/CMTC/TR-80/2. Aug.

Macdonald, R.G. and Caswell, G.R.
1983: Design and Analysis of Fracture Treatments in the Medicine Hat Formation Using a Hydraulic Fracture Simulator
34th Ann. Tech. Mtg., Pet. Soc. CIM, Banff, May 10-13; Preprint 83-34-35, 16 p.

Nordgren, R.P.
1972: Propagation of a Vertical Hydraulic Fracture
SPE 3009P, 9 p.

Nolte, K.G.
1979: Determination of Fracture Parameters from Fracturing Pressure Decline
Paper No.SPE 8041, 54th Ann. Fall Tech. Conf. & Exhib., Las Vegas, NV, Sept.

Nolte, K.G. and Smith, M.B.
1979: Interpretation of Fracturing Pressures
Paper No.SPE 8297, 54th Ann. Fall Tech. Conf. & Exhib., Las Vegas, NV, Sept.

Perkins, T.K. and Kern, L.R.
1961: Widths of Hydraulic Fractures
SPE 89P, 13 p.

Rogers, L.A.; Simonson, E.R.; Abou-Sayed, A.S. and Jones, A.H.
1977: Massive Hydraulic Fracture Containment Analysis Utilizing Rock Mechanics Considerations
Proc. Massive Hydraulic Frac. Symp., U. of Oklahoma, Norman.

Sarda, J.P.
1981: Use of High-Strength Ceramic Beads for Propping Deep Hydraulic Fractures
J. of Pet. Tech., v.33, pp 55-56, Jan.

Settari, A.
1979: Simulation of Hydraulic Fracturing Processes
SPE Paper No.7693, 5th SPE Symp. on Numerical Simulation Denver, CO.

Simonson, E.R.; Abou-Sayed, A.S. and Clifton, R.J.
1978: Containment of Massive Hydraulic Fractures
SPE 6089P, 6 p.

1976: Containment of Massive Hydraulic Fractures
Paper No.SPE 6089, 52st Ann. Fall Tech. Conf. & Exhib., New Orleans, Oct.

Sinclair, A.R. and Graham, J.W.
1978: A New Proppant for Hydraulic Fracturing
Paper presented at ASME Energy Tech. Conf., Houston, TX, Nov.

Smith, M.E.; Logan, J.M. and Wood, M.D.
1980: Fracture Azimuth - A Shallow Experiment
J. of Energy Resource Tech., v.102, pp 99-105, June.

Thakur, P.E. and Davis II, J.G.
1977: How to Plan for Methane Control in Underground Coal Mines
Min. Eng. v. 29.

Veatch, R.
1980: Massive Hydraulic Fracturing
Proc. of Geothermal Reservoir Well Stimulation Symp., San Francisco, Feb. 1980 (Paper not submitted for publication).

Warpinski, N.R.; Schmidt, R.A. and Northrop, D.A.
1982: In Situ Stress: The Predominant Influence on Hydraulic Fracture Containment
Jour. of Pet. Tech., March.

1980: In Situ Stresses: The Predominant Influence on Hydraulic Fracture Containment
Paper No.SPE 8932, Unconventional Gas Recovery Symp., Pittsburgh, PA, May.

7.2 SELECTED BIBLIOGRAPHY

Anon
1971: **Design and Development of Horizontal Borehole Packers for Use in Coal Beds**
US Bu. Mines Rep. OFR 6-72, Dec. Work performed under Contract No. H0111021 by James H. Cobbs Engineering, Tulsa, OK.

Abou-Sayed, A.S.; Sinha, K.P. and Clifton, R.J.
1984: **Evaluation of the Influence of In Situ Reservoir Conditions on the Geometry of Hydraulic Fractures Using a 3-D Simulator: Part 1 - Technical Approach**
SPE/DOE/GRI - 2877

Advani, S.H.
1980: **Finite Element Model Simulations Associated with Hydraulic Fracturing**
SPE Paper No.8541, Unvonventional Gas Recovery Symp., Pittsburgh, PA, May.

Ahmed, U.; Kelkar, S. and Schatz, J.
1983: **Mini Frac An Aid to Formation In Situ Stress and Permeability Measurements**
Proc. 24 US Symp. on Rock Mechanics, pp 319.

Agarwal, R.G.; Carter, R.D. and Pollock, C.B.
1977: **Evaluation and Prediction of Performance of Low Permeability Gas Wells Stimulated by Massive Hydraulic Fracturing**
Papr No. SPE 6808, 52nd Ann. Fall Tech. Conf. & Exhib., Denver, CO, Oct.

Ahmed, U.; Abou-Sayed, A.S. and Jones A.H.
1979: **Experimental Evaluation of Fracturing Fluid Interaction with Tight Reservoir Rocks and Propped Fractures**
Paper No. SPE 7922, SPE/DOE Symp. on Low Permeability Gas Reservoirs, Denver, CO, May 20-22.

Atkinson, Charles H.
1975: **Rio Blanco Massive Hydraulic Fracturing Demonstration**
US Bu. Mines Pet. Research Prog. Tech. Prog. Rep. 88.

Baltino, S. and Hargraves, A.J.
1982: **Seam Gas Drainage Experiments in Some Collieries of B.H.P.**
Proc. of Symp. on Seam Gas Drainage with Particular Reference to the Working Seam, (Ed. A.J. Hargraves), Univ. of Wollongong, NSW, Australia, May 11-14.

AMCL

Biot, M.A.; Masse, L. and Medlin, W.L.
1982: A Two-Dimensional Theory of Fracture Propagation
SPE 11067

Boyer, C.M. II, and Stubbs, P.B.
1983: Measurement of Dynamic Coalbed Reservoir Conditions Required to Design Near-Mine Methane Control Activities in the Warrior Coal Basin
US Dept. of Energy DOE/ET/14204-1477 (DE 94000226), Feb. Work performed under Contract No. DE-AC21-79ET14204 by the US Steel Corp., Research Lab., Monroeville, PA.

Cleary, M.P.
1980: Comprehensive Design Formulae for Hydraulic Fracturing
SPE Paper No.9259, 55th Ann. Fall Tech. Conf. & Exhib., Dallas, TX, Sept.

Cinco-L, H. and Samaniego-V, F.
1978: Transient Pressure Analysis for Fractured Wells
Paper No. SPE 7490, 53rd Ann. Fall Tech. Conf. & Exhib., Houston, TX, Oct.

Clifton, R.J. and Abou-Sayed, A.S.
1981: A Variational Approach to the Prediction of the Three-Dimensional Geometry of Hydraulic Fracturing
SPE Paper No.9879, SPE/DOE Low Permeability Gas Reservoirs Symp., May.

1979: On the Computation of the Three-Dimensional Geometry of Hydraulic Fractures
Paper No.SPE 7943, SPE/DOE Symp. on Low Permeability Gas Reservoirs, Denver, CO, May.

Cooke, Jr., C.E. and Gidley, J.L.
1979: High-Strength Proppant Extends Deep Well Fracturing Capabilities
Proc. of the 10th World Pet. Cong., v.3 (Production), Bucharest.

Deul, M. and Kim, A.G.
1975: Methane in Coal: From Liability to Asset
Min. Cgr. J. v.61/11, Nov.

Dobkins, Terrell A.
1979: Methods to Better Determine Hydraulic Fracture Height
SPE 8403

Dobrynin, Valery M.
1962: Effect of Overburden Pressure on Some Properties of Sandstones
SPE 461P, 7 p.

AMCL

Doe, T.; Ingevald, K.; Strindell, L.; Haimson, B. and Carlsson, H.
1981: **Hydraulic Fracturing and Overcoring Stress Measurements on a Deep Borehole at the Stripa Test Mine, Sweden**
Proc. 22 US Symp. on Rock Mechanics, pp 403.

Dougherty, R.L. and Abou-Sayed, A.S.
1984: **Evaluation of the Influence of In Situ Reservoir Conditions on the Geometry of Hydraulic Fractures Using a 3D Simulator**
SPE Paper No.13275, 59th Ann. Tech. Conf. & Exhib., Houston, TX, Sept. 16-19.

Elder, C.H.
1977: **Effects of Hydraulic Stimulation on Coalbeds and Associated Strata**
US BU. Mines, RI 8260.

Elder, C.H. and Deul, M.
1975: **Hydraulic Stimulation Increases Degasification Rates of Coalbeds**
US Bu. Mines, RI 8047.

1974: **Degasification of the Mary Lee Coalbed Near Oak Grove, Jefferson County, Alabama, by Vertical Borehole in Advance of Mining**
US Bu. Mines, RI 7968.

Enever, J.
1979: **Fracture at Work**
The 4th Tewksbury Symp. on Fracture, Univ. of Melbourne, Australia, pp 5.1.

Gray, D.H.; Fatt, L and Bergamini, G.
1963: **The Effect of Stress on Permeability of Sandstone Cores**
SPE 531P, 6 p.

Gretener, P.E.
1981: **Pore Pressure: Fundamentals, General Ramifications, and Implications for Structural Geology (revised)**
AAPG Education Course Note Series #4.

Haimson, G.C.
1976: **The Hydrofracturing Stress Measuring Technique - Method and Recent Field Results in the US**
Proc. Int. Soc. for Rock Mechanics Symp. pp 23-30.

Herget, G.
1982: **High Stress Occurrences in the Canadian Shield**
in 'Issues in Rock' Mechanics, Chapter 21, Proc. 23rd Symp. on Rock Mechanics, SME of AIME, pp 203-210.

Houseknecht, D.W.
1982: Probability of Encountering Coalbed Discontinuities During Vertical and Horizontal Borehole Drilling
U.S. Bu. Mines, R.I. 8665.

Howard, G.C. and Fast, C.R.
1970: Hydraulic Fracturing
Mono. v.2, Henry L. Dohery Series, Soc. of Pet. Eng. of AIME.

Kahil, A.A. and Masszi, D.
1982: Technical Considerations for the Design of a Demethanization Program
in Proc. Symp. Seam Gas Drainage with Particular Reference to the Working Seam. (Ed. A.J. Hargraves), Univ. of Wollongong, NSW, Australia, May 11-14.

Kehle, Ralph O.
1964: The Determination of Tectonic Stress Through Analysis of Hydraulic Well Fracturing
Jour. of Geophys. Research, v.69/2, pp 259.

Lambert, S.W.; Trevits, M.A. and Steidl, P.F.
1979: Methane Drainage Ahead of Mining Using Foam Stimulation, Mary Lee Coalbed, Alabama
US Dept. Energy Rep. RI PMTC-3(79), Jan.

1978a: Methane Drainage: Experience with Hydraulic Stimulation Through Slotted Casing
US Bu. Mines, RI 8295.

1978b: Effective Placement of Coalbed Gas Drainage Wells
US Dept. of Energy Rep. RI-PMOC-2(78), Sept.

Mahoney, J.V.; Stubbs, F.C.; Schwerer, F.C., III, and Dobscha, F.X.
1981: Effects of a No-Proppant Foam Stimulation Treatment on a Coal Seam Degasification Borehole
J. Pet. Tech. v.33/11.

Maksimovic, S.D.; Elder, C.H. and Kissell, F.N.
1977: Hydraulic Stimulation of a Surface Borehole for Gas Degasification
US Bu. Mines, RI 8228.

McGuire, W.J. and Sikora, V.J.
1960: The Effect of Vertical Fractures on Well Productivity
Trans. AIME, v.219, pp 401-403.

Medlin, W.L. and Masse, L.
1982: Plasticity Effects in Hydraulic Fracturing
SPE 11068.

AMSL

Oyler, D.C. and Diamond, W.P.
1982: Drilling a Horizontal Coalbed Methane Drainage System From a Directional Surface Borehole
US Bu. Mines, R.I. 8842

Perkins, T.K. and Krech, W.W.
1968: The Energy Balance Concept of Hydraulic Fracturing
SPE Journal, March.

Prats, M.; Hazenbroek, P. and Stickler, W,R,
1962: Effect of Vertical Fractures on Reservoir Behavior - Compressible Fluid Case
Soc. of Pet. Eng. J., v.2, pp 87-94, June.

Rieke, H.H. and Galliers, F.
1981: Reservoir and Production Characteristics of Composite Coal/Sandstone Gas Reservoirs
SPE Paper 10376.

Rosepiler, M.J.
1979: Determination of Principal Stresses and Confinement of Hydraulic Fractures in Cotton Valley
SPE 8405.

Spindler, G.R. and Poundstone, W.N.
1960: Experimental Work in the Degasification of the Pittsburgh Coal Seam by Horizontal and Vertical Drilling
Paper presented at the SME AIME Mtg., New York, NY, Feb. 14-18.

Steidl, P.F.
1978: Foam Stimulation to Enhance Production from Degasification Wells in the Pittsburgh Coalbed
US Bu. Mines, RI 8286.

Steidl, P.F. and Lambert, S.W.
1978: Foam Stimulation for Enhanced Recovery from coal-Gas Wells
Proc. of the AAPG-SEPM Ann. Conv., Oklahoma City, OK, Apr. 9-12.

Stubbs, P.B.; Dobscha, F.X. and Mahoney, J.V.
1979: Degasification of the Blue Creek Coal Seam at Oak Grove Mine
Proc. of 2nd Ann. Methane Recovery from Coalbeds Symp. (Ed. R.L. Wise), Apr. 18-20. US Dept. Energy Rep. METC/SP-79/9, Apr.

Thompson, R.W.; Menezes, J.J. and Gray, K.E.
1977: Roof Stability and Subsidence in In Situ Gasifiction of Coal. in 'Energy Resources and Excavation Technology'
Proc. 18th US Symp. on Rock Mechanics, pp 2B1-1.

Tinsley, J.M.; Williams, J.R.; Tiner, R.L. and Malone, W.T.
1969: Vertical Fracture Height - Its Effect on Steady-State Production Increase
J. of Pet. Tech., v.21, pp 633-638, May.

Trevits, M.A.
1980: Observations of Mined Through Stimulation Treatments in Vertical Coalbed Methane Drainage Boreholes
Unpub. ms. US Bu. Mines, Pittsburgh, PA.

APPENDIX A

Equations for Fracture Width at the Wellbore

EQUATIONS FOR FRACTURE WIDTH AT THE WELLBORE FOR DYNAMIC CONDITIONS

1. Fracture width as described by Perkins and Kern (1961) for vertical fractures:

   Assumptions: - no slip at boundary interfaces
   - laminar flow in fracture

$$W = 0.38 \left[\frac{Q\mu L}{E}\right]^{\frac{1}{4}}$$

   Where:

   W = maximum fracture width at wellbore, (in)
   Q = total pump rate, (bbl/min)
   μ = effective fracture fluid viscosity, (cp)
   L = fracture length from wellbore, (ft)
   E = Young's Modulus of formation rock, (psi)

2. Fracture width as described by Geertsma and deKlerk (1969) for vertical fractures:

   Assumptions: - slip occurs at boundary interfaces
   - laminar flow in fracture

$$W = 2.1 \left[\frac{\mu Q L^2}{Gh}\right]^{\frac{1}{4}}$$

   Where:

   W = maximum fracture width at wellbore, (in)
   Q = total pump rate, (bbl/min)
   μ = effective fracture fluid viscosity, (cp)
   L = fracture length from wellbore, (ft)
   h = fracture height, (ft)
   G = shear modulus of formation rock, (psi)

AMCL

3. Fracture width as described by Perkins and Kern (1961) for horizontal fractures.

Assumption: - laminar flow in fracture

$$W = 0.22\left[\frac{Q\mu R}{E}\right]^{\frac{1}{4}}$$

Where:

W = maximum fracture width at wellbore, (in)
Q = total pump rate, (bbl/min)
μ = effective fracture fluid viscosity, (cp)
R = radius of fracture, (ft.)
E = Young's Modulus of formation rock, (psi)

4. Fracture width as described by Geertsma and deKlerk (1969) for horizontal fractures:

Assumption: - laminar flow in fracture

$$W = 2\left[\frac{\mu QR}{G}\right]^{\frac{1}{4}}$$

Where:

W = maximum fracture width at wellbore, (in)
Q = total pump rate, (bbl/min)
μ = effective fracture fluid viscosity, (cp)
R = radius of fracture, (ft)
G = shear modulus of formation rock, (psi)

Darcy's Law for flow of an incompressible fluid through rock filled with only one fluid (Allen and Roberts, 1982):

$$q = 1.127 \times 10^{-3} \left[\frac{KA(P_2 - P_1)}{\mu L} \right]$$

Where:

q	=	flow rate, (bbl/day)
K	=	permeability, (mD)
A	=	flow area, (ft^2)
μ	=	viscosity, (cp)
L	=	flow length, (ft)
P_1, P_2	=	inlet and outlet pressures, (psi)

Note: If more than one fluid is present in the rock, relative permeabilities must be used to describe the flow rate for each fluid.

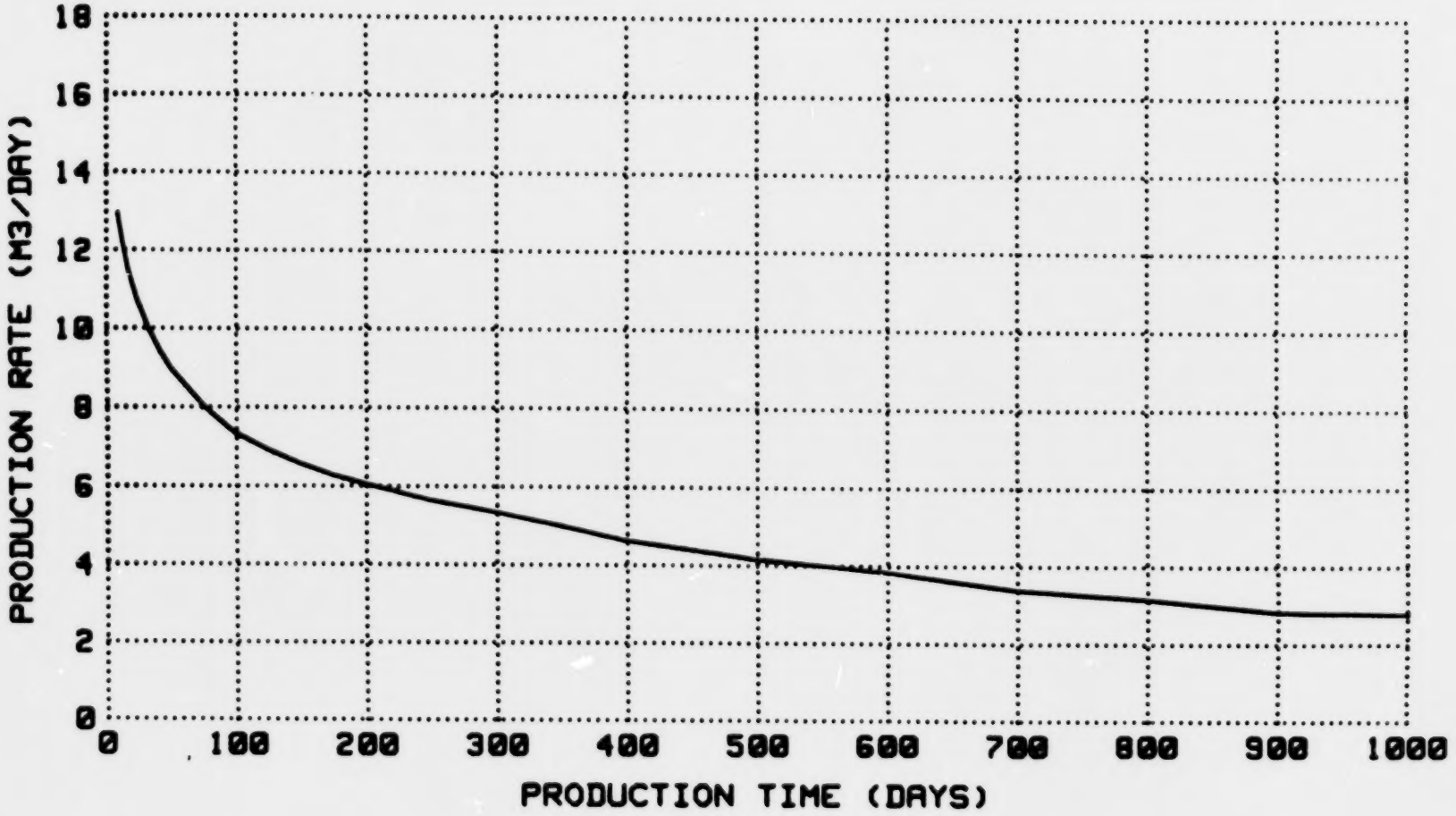
APPENDIX B

Petroleum Case History No.1

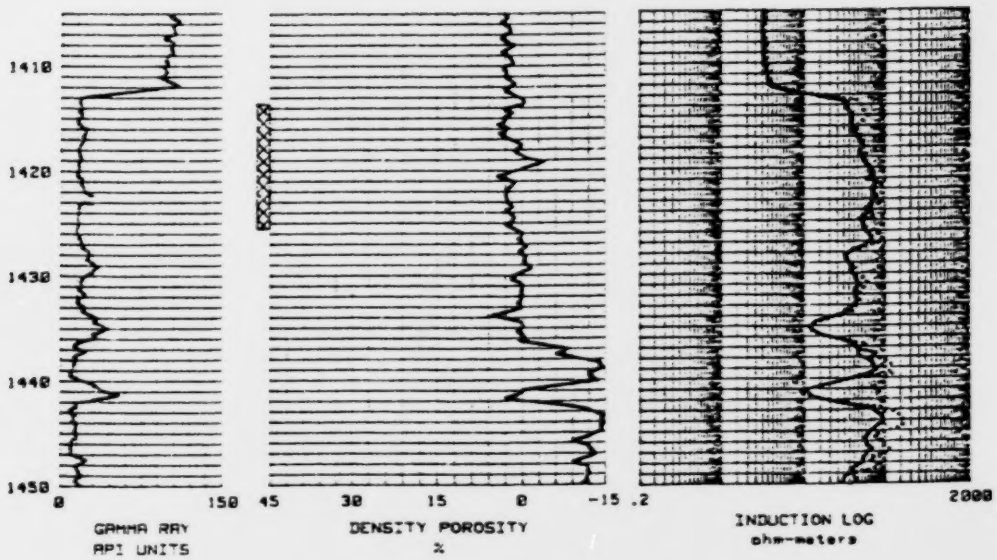
Ulster et al. LOON

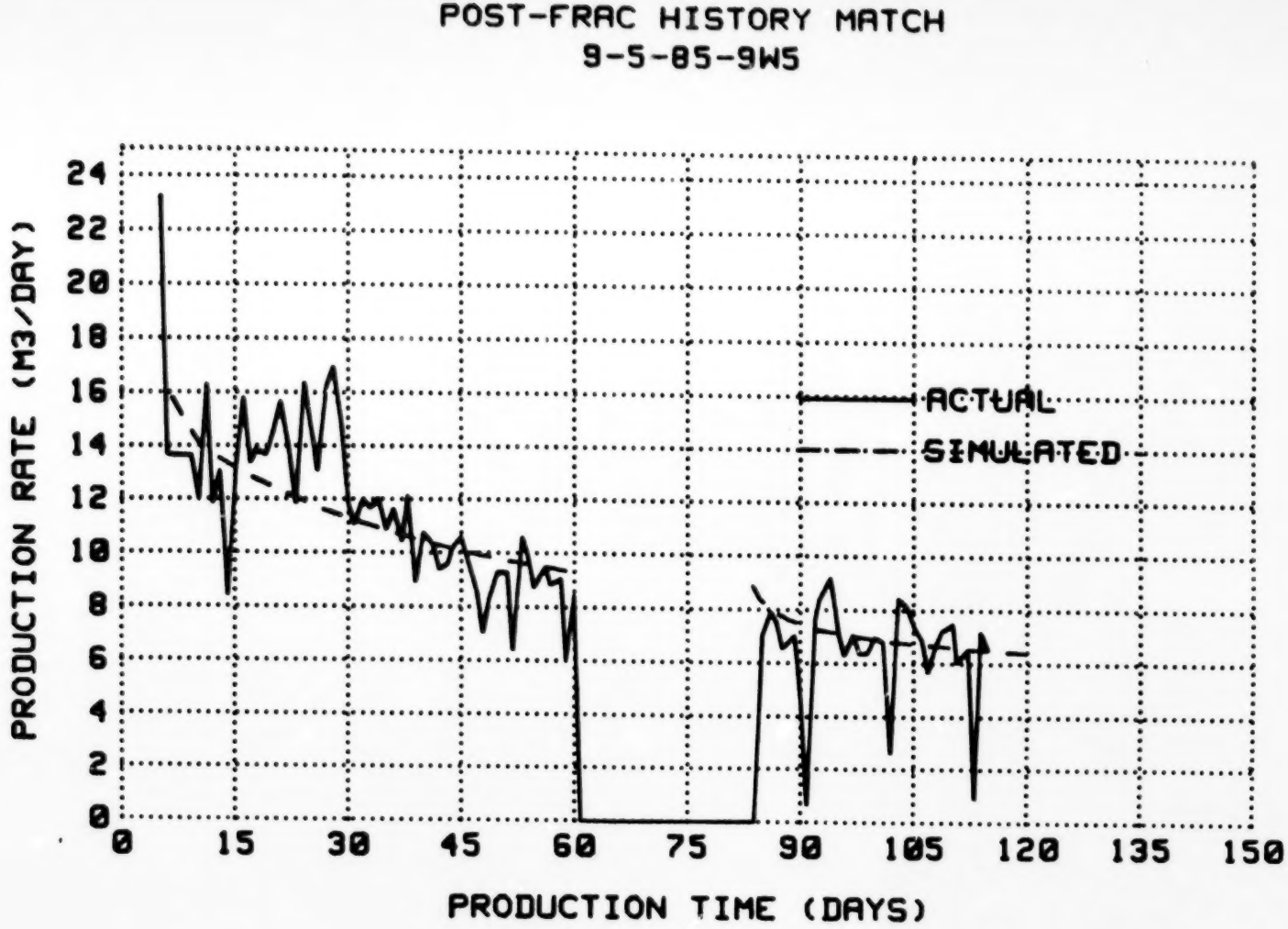
Attached:

1. Predicted post frac production
2. Well Log
3. Actual post frac production
4. One Wing of Frac'd Well
5. Treatment Program

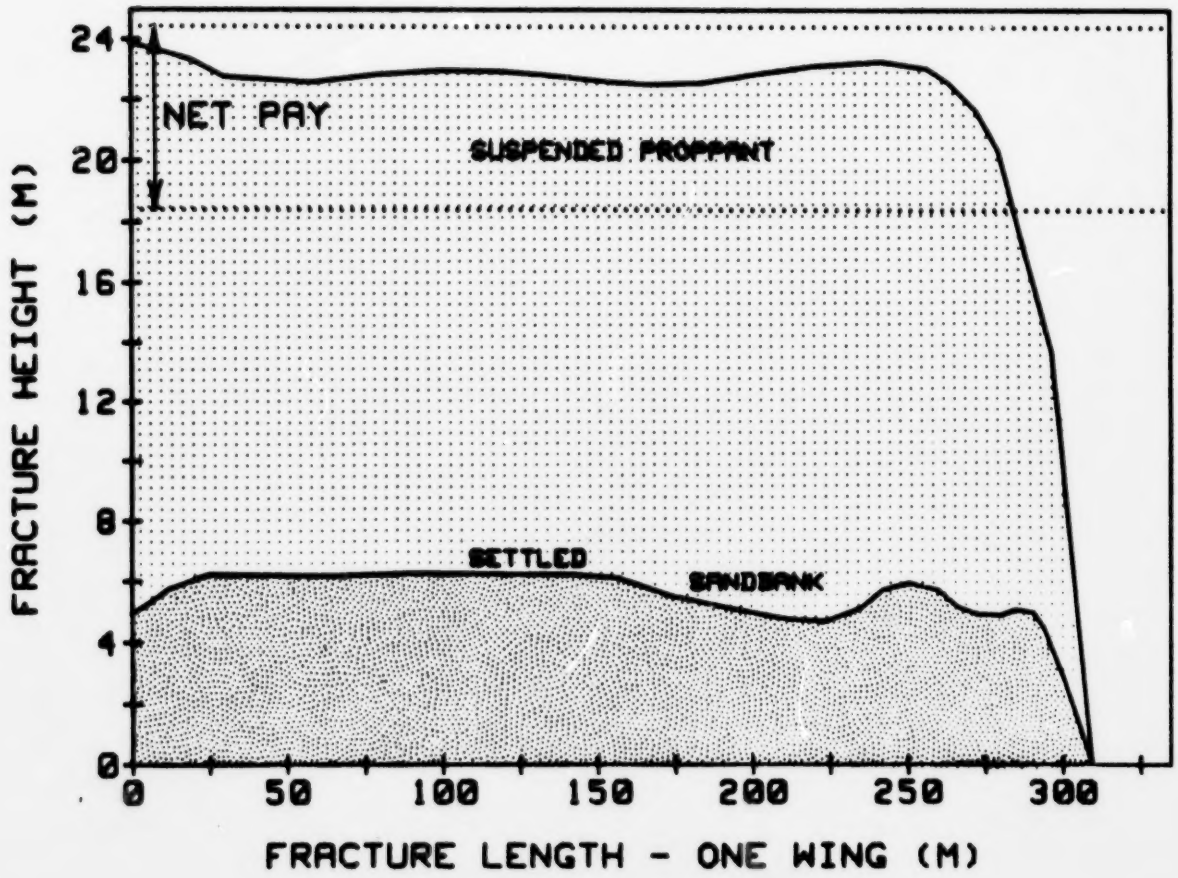

PREDICTED POST-FRAC PRODUCTION
9-5-85-9W5
100 TONNES
PRODUCTION RATE (M3/DAY)
0
2
4
6
8
10
12
14
16
18
0
100
200
300
400
500
600
700
800
900
1000
PRODUCTION TIME (DAYS)

S-5-85-SWS


1410
1420
1430
1440
1450
0
150
GAMMA RAY
API UNITS
45
30
15
0
-15
DENSITY POROSITY
%
.2
2000
INDUCTION LOG
ohm-meters


POST-FRAC HISTORY MATCH
9-5-85-9W5
PRODUCTION RATE (M3/DAY)
0
2
4
6
8
10
12
14
16
18
20
22
24
0
15
30
45
60
75
90
105
120
135
150
PRODUCTION TIME (DAYS)
ACTUAL
SIMULATED

PROPPANT DISTRIBUTION @ CLOSURE
9-5-85-9W5
100 TONNES



POLYEMULSION FRAC

ULSTER ET AL LOON

9-5-85-9-W5M

BASIC WELL DATA

Formation:	*Slave Point (oil)*
Perforations:	*1413.5 - 1425.3 m*
Casing:	*139.7 mm, 20.83 kg/m*
Frac Gradient:	*18.1 kPa/m*
BHST:	*39°C*
BHSP:	*14.65 MPa*
Porosity:	*10%*
Permeability:	*0.45 md*

PROCEDURE

EQUIPMENT: 640 kW Frac Pumpers
Standby VT-1200 frac pumper
Blender to 2.4 m^3/min
Fire Protection Services
Iron Truck
Treatment Analysis Unit

SAFETY: Spot tanks a minimum of 50 m from the wellhead.

NOTE: Water to be preheated to 24°C prior to gelling.

Conduct pretreatment safety meeting with all personnel on location and discuss:

Pressure limitations (to be verified with oil company representative)
Job procedure and personnel responsibilities
Safety procedures

RIG UP: Frac well down casing.

PRESSURE:

Pressure test	29 MPa
Maximum	28 MPa

RATE: Anticipated rate is 2.4 m^3/min at 16 MPa.

BREAKER: Breaker F to be added "on the fly" at 0.12 kg/m^3 based on the water portion only. Breaker S to be premixed in water at 0.30 kg/m^3.

PAD: Fill well, break down formation and establish a feedrate with a 40.0 m^3 pad of polyemulsion fluid.

SAND: Use the attached proppant schedule as a guide for the placement of:

100.0 tonne 20/40 mesh sand

FLUSH: Flush with 17.0 m^3 of crude oil. This volume represents a 1.0 m^3 underflush and must be recalculated on location.

SHUT IN: Leave well shut in overnight for frac to close and gel to break, then flow or swab well back through properly staked lines to an open rig tank to clean up and evaluate treatment.

POLYEMULSION PROPPANT SCHEDULE

ULSTER ET AL LOON SLAVE POINT FORMATION

Slur per Stage m3	Cum Slur m3	Oil per Stage m3	Cum Oil m3	Water per Stage m3	Cum Water m3	Sand Conc kg/m3	Cum Sand tonne	Remarks
								Start cum. values
40.0	40.0	26.7	26.7	13.3	13.3			Pad volume
4.3	44.3	2.7	29.3	1.3	14.7	200	0.80	2040 mesh sand
4.6	48.9	2.7	32.0	1.3	16.0	400	2.40	2040 mesh sand
4.9	53.8	2.7	34.7	1.3	17.3	600	4.80	2040 mesh sand
5.2	59.1	2.7	37.3	1.3	18.7	800	8.00	2040 mesh sand
5.5	64.6	2.7	40.0	1.3	20.0	1000	12.00	2040 mesh sand
14.6	79.2	6.7	46.7	3.3	23.3	1200	24.00	2040 mesh sand
14.6	93.7	6.7	53.3	3.3	26.7	1200	36.00	2040 mesh sand
14.6	108.3	6.7	60.0	3.3	30.0	1200	48.00	2040 mesh sand
15.3	123.6	6.7	66.7	3.3	33.3	1400	62.00	2040 mesh sand
15.3	139.0	6.7	73.3	3.3	36.7	1400	76.00	2040 mesh sand
7.7	146.7	3.3	76.7	1.7	38.3	1400	83.00	2040 mesh sand
17.1	163.8	7.1	83.8	3.5	41.9	1600	100.00	2040 mesh sand
		17.0						Oil flush
							100.00	tonne total proppant

Fluid Requirements

Crude Oil	Program above	83.8 m3(527 bbl)
	Flush	17.0 m3(107 bbl)
	Tank bottoms	13.3 m3(83 bbl)
	Total	114.0 m3(717 bbl)
	Requires 2 X 63.3 m3 tanks	
Water	Program above	41.9 m3(263 bbl)
	Tank bottoms	6.1 m3(39 bbl)
	Total	48.0 m3(302 bbl)
	Requires 1 X 63.3 m3 tanks	

APPENDIX C

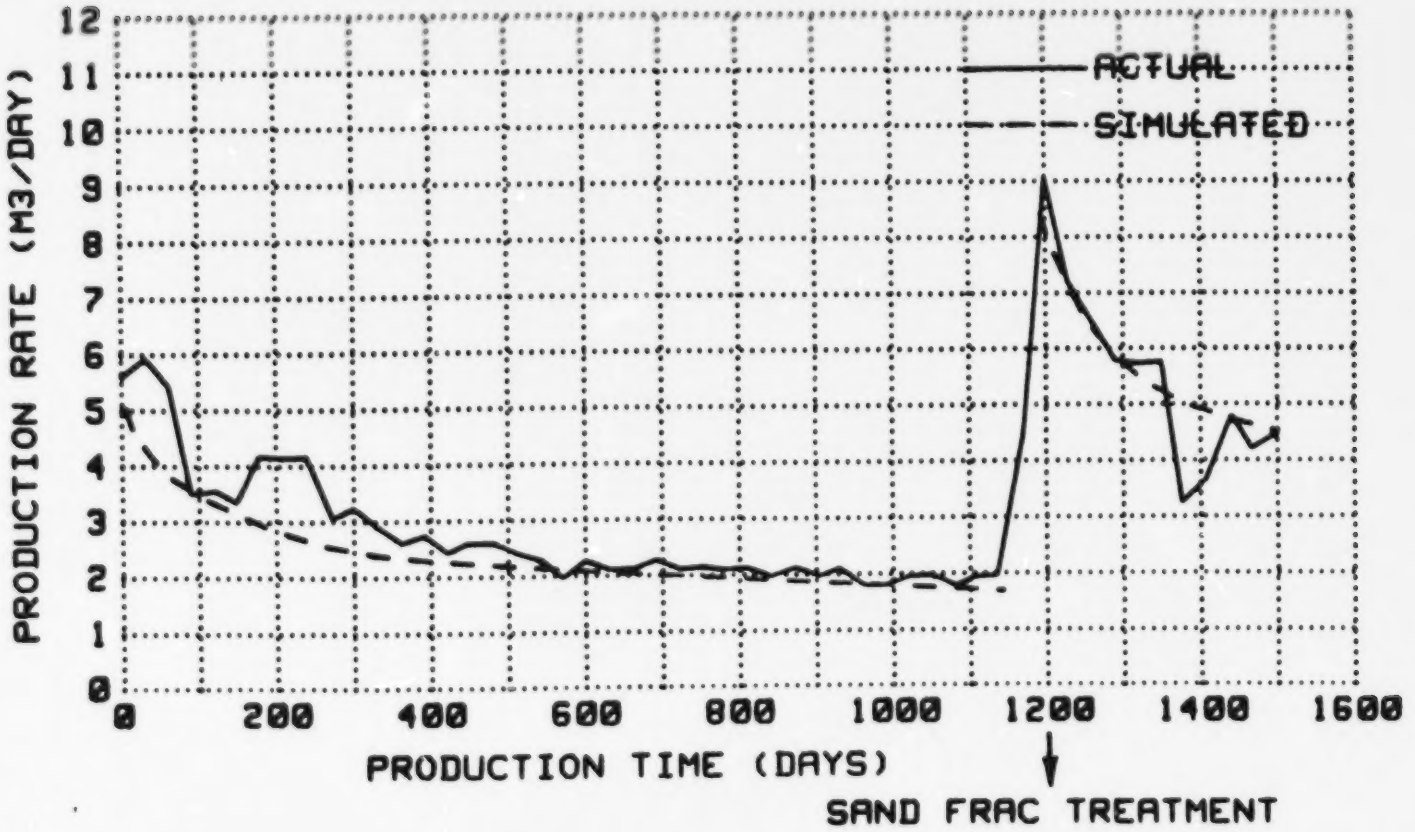
Petroleum Case History No.2

Union Red Earth

Attached:

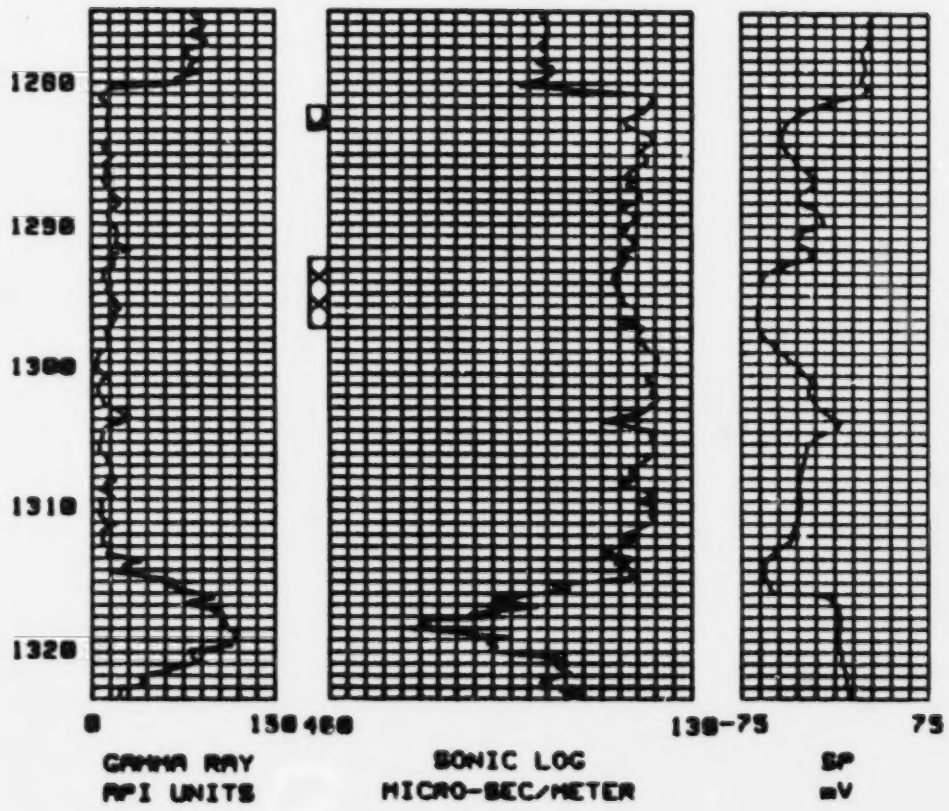
1. Pre and post frac production
2. Well Log
3. One Wing of Frac'd Well
4. Treatment Program

PRE-FRAC/POST-FRAC HISTORY MATCH
10-2-88-9W5

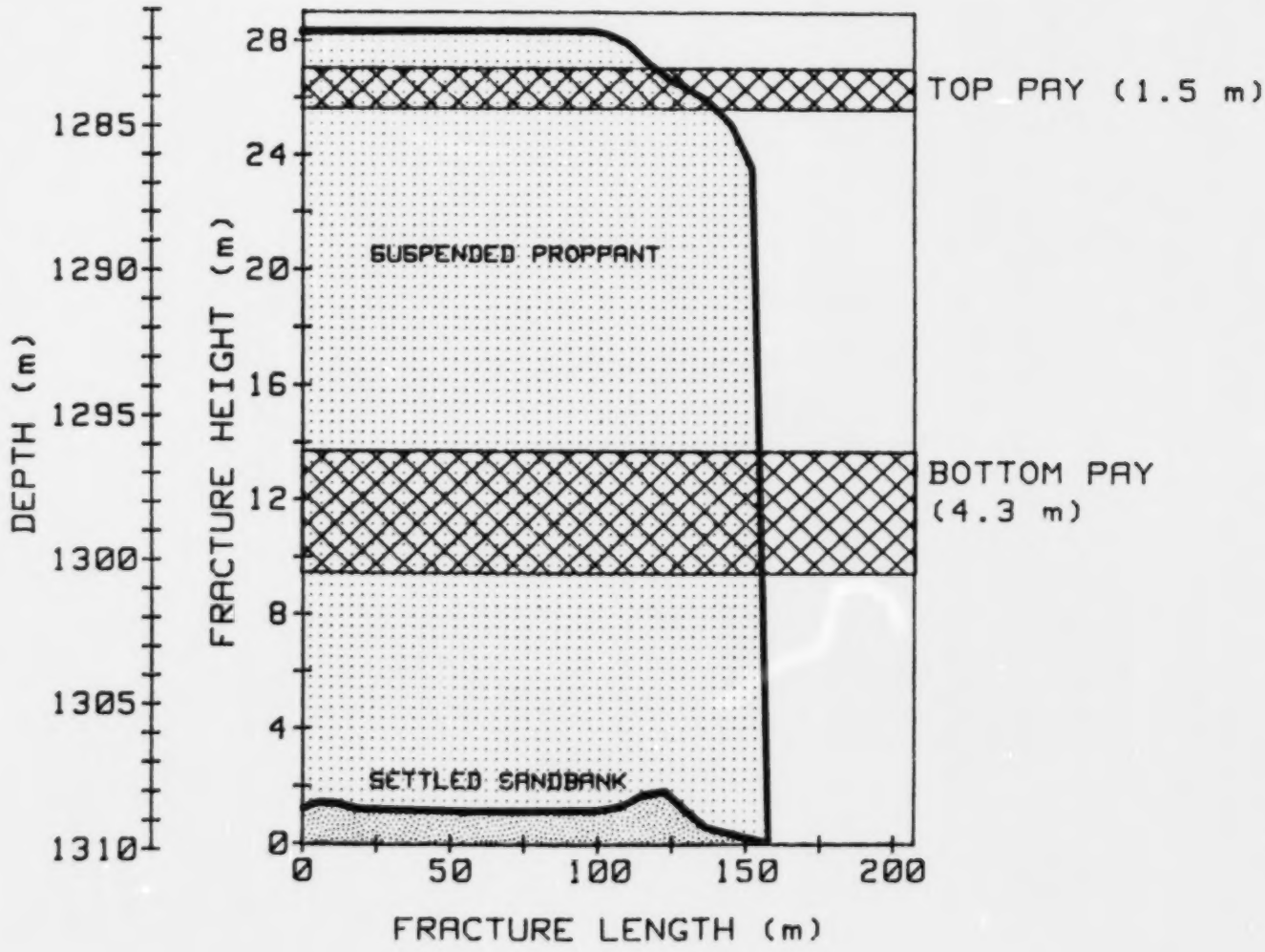


AMSL

10-2-88-9WS


1280
1290
1300
1310
1320
0
150
400
150
-75
75
GAMMA RAY
API UNITS
SONIC LOG
MICRO-SEC/METER
SP
mV

PROPPANT DISTRIBUTION @ CLOSURE
LAYERED MODEL
10-2-88-9W5



ULTRAVIS LPW-2 WATER FRAC

UNION RED EARTH

10-2-88-9-W5M

BASIC WELL DATA

Formation:	*Slave Point (oil)*
Perforations:	*1282.6 - 1284.0 m 7 SPM*
	1295.4 - 1299.1 m 7 SPM
	1300.3 - 1300.9 m 7 SPM
Tubing:	*60.3 mm, 6.99 kg/m J-55*
Casing:	*114.3 mm, 15.7 kg/m*
Frac Gradient:	*19.4 kPa/m*
BHP:	*11,700 kPa*
BHT:	*42°C*

AMCL

PROCEDURE

1. *Spot 3 tanks on location a minimum of 50 m upwind from wellhead and fill as per the attached fluid requirements page.*

   Water should be heated to 24°C (75°F) to obtain optimum gel.

2. *Move in the following fracturing equipment:*

   510 kW frac pumpers use VT-1200
   Blender to 1.9 m^3/min
   Iron truck
   Treatment analysis unit
   Standby VT-1200 frac pumper

2. *Conduct a pretreatment safety meeting with all personnel on location detailing program, pressure limitations, personnel responsibilities, and safety precautions. Discuss pressure limitations with oil company representative on location.*

3. *Prepared Ultravis LPW-2 frac fluid and breaker as per the attached blending procedure. All water to contain 3% KCl.*

5. *Rig up equipment to frac well down manifolded tubing and annulus.*

6. *Rig in a sandoff line. In the event of a sandoff this line can be opened and the sand circulated out of the well.*

7. *Pressure test surface equipment, lines and wellhead to 28,000 kPa. Do not exceed 26,000 kPa during treatment.*

8. *Anticipated rate is 1.9 m^3/min at 16,000 kPa.*

   NOTE: Minimum rate during treatment 1.1 m^3/min
   Maximum rate during treatment 2.0 m^3/min

9. *All frac fluid to be treated with QTX-25 Complexer at 2.0 L/m^3.*

10. *Breakdown formation and establish a feedrate with a 32.0 m^3 pad of complexed frac fluid.*

11. *Use the attached proppant schedule as a guide for the placement of:*

    34.0 tonne 20/40 mesh sand

12. *Flush with 8.5 m^3 friction reduced water running F-655 friction reducer at 2.0 L/m^3 added "on the fly". This is an underflush by 1.3 m^3.*

13. *Leave well shut in for 4 hours for frac to close, then flow or swab well back through properly staked lines to an open rig tank to clean up and evaluate treatment.*

AMCL

PROPPANT SCHEDULE

UNION RED EARTH SLAVE POINT FORMATION

Slurry per Stage m3	Cum Slurry m3	Water per Stage m3	Cum Water m3	Sand Conc kg/m3	Cum Sand tonne	Remarks
						Start cum values
32.0	32.0	32.0	32.0			Pad volume
2.7	34.7	2.5	34.5	200	0.50	2040 mesh sand
2.9	37.6	2.5	37.0	400	1.50	2040 mesh sand
3.1	40.6	2.5	39.5	600	3.00	2040 mesh sand
3.3	43.9	2.5	42.0	800	5.00	2040 mesh sand
6.9	50.8	5.0	47.0	1000	10.00	2040 mesh sand
7.3	58.1	5.0	52.0	1200	16.00	2040 mesh sand
7.3	65.4	5.0	57.0	1200	22.00	2040 mesh sand
7.3	72.7	5.0	62.0	1200	28.00	2040 mesh sand
7.3	80.0	5.0	67.0	1200	34.00	2040 mesh sand
8.5	88.5	8.5	75.5			Flush
					34.00	tonne total proppant

Gelled Water Requirements

Program above	67.0 m3
Flush	8.5 m3
Tank bottoms	13.5 m3
Total	89.0 m3

Requires 1 X 63.3 m3 tanks and 1 X 33.2 m3 tanks

Chemical Requirements

KCL salt	30.00 kg/m3	2670 kg
WS-60NE surf	2.00 L/m3	178 L
NowpHix 6X	1.70 kg/m3	150 kg
LSR-1NB gel	7.20 kg/m3	641 kg
QTX Complexer	2.00 L/m3	134 L
Gel Breaker F	0.85 kg/m3	64 kg

Breaker F to be added on the fly according to the attached breaker schedule.

APPENDIX D

Petroleum Case History No.3

Cabre et al Mellowdale

Attached:

1. Post frac production
2. Formation properties
3. Rheological properties of fracturing fluids
4. One Wing of Simulated Fractured Well
5. Treatment Program

CASE HISTORY #3

CABRE ET AL MELLOWDALE

(Basal Quartz Sandstone)

Attached

1) Post frac production

2) Formation properties

3) Rheological properties of fracturing fluids

4) One wing of simulated fractured well

5) Treatment program

CABRE ET AL MELLOWDALE

Formation Data

RESERVOIR

Permeability to Oil	21 md
Porosity	19.2%
Drainage Area	65 hectares
Depth (Midpoint of Pay)	1081.3 m KB
Reservoir Temperature	47°C
Reservoir Pressure (initial)	8310 kPa
Water Saturation	35.0%
Irreducible Water Saturation	27.0%

ROCK PROPERTIES

Overburden Stress Gradient	22.76 kPa/m
Effective Stress Ratio	0.3591
Biot Constant	0.950
Poisson Ratio	0.180
Young's Modulus	39.3×10^{6} kPa
Tensile Strength	4130 kPa
Rock Compressibility	5.40×10^{-7} kPa

CABRE ET AL MELLOWDALE

Rheological Properties of Polyemulsion

Reservoir Temperature	47.0°C
Chemical Loading	
LSR-1NB (Base Gel)	3.6 kg/m^3
Nowphix 6X (Buffer)	1.0 kg/m^3
Breaker S	0.6 kg/m^3
Breaker F	0.1 kg/m^3
WS-60NE (Surfactant)	8.0 L/m^3
DL-15	12.0 L/m^3
KCl	30.0 kg/m^3
n'	0.530
k'	0.040
Maximum Viscosity (170 sec^{-1})	150.0 cp
Minimum Viscosity	2.0 cp
Break Time	8 hours

AMCL

CABRE ET AL MELLOWDALE

Post-Frac Production

	Hours	Oil (m^3)	Gas (m^3)	W
OCTOBER 1984		62.8	44.7 x 10^3	0
NOVEMBER 1984	222	223.5	145.6	34.8
DECEMBER 1984	744	366.7	395.1	140.2
JANUARY 1985	341	189.1	244.6	109.6

PROCEDURE

EQUIPMENT:
700 kW Frac Pumpers
Blender to 2.4 m^3/min
Fire Protection Services
Iron Truck
Treatment Analysis Unit
Radioactive tracer sand

SAFETY: Spot tanks a minimum of 50 m from the wellhead.

NOTE: Water to be preheated to 24°C prior to gelling.

Conduct pretreatment safety meeting with all personnel on location and discuss:

Pressure limitations (to be verified with oil company representative)
Job procedure and personnel responsibilities
Safety procedures

RIG UP: Frac well down manifolded tubing and annulus

PRESSURE:

Pressure test	29 MPa
Maximum	26 MPa

RATE: Anticipated rate is 2.4 m^3/min at 16 MPa.

ACID: Spearhead frac with 1.0 m^3 15% HCl treated acid.

4.0 L AI-250 inhibitor
1.0 L WS-50 surfactant
4.0 L DL-22 demulsifier

BREAKER: Breaker F to be added "on the fly" at 0.12 kg/m^3 based on the water portion only. Breaker S to be premixed in water at 0.6 kg/m^3 in the water portion.

PAD: Break down formation and establish a feedrate with a 25.0 m^3 pad of polyemulsion fluid. This volume includes the hole fill.

SAND: Use the attached proppant schedule as a guide for the placement of:

20.0 tonne 20/40 mesh sand

Run radioactive tracer sand as recommended by tracer company representative.

FLUSH: Flush with 12.0 m^3 of friction reduced crude oil. This volume represents a 0.8 m^3 underflush and must be recalculated on location. Run F-100 friction reducer "on the fly" at 5 L/m^3.

SHUT IN: Leave well shut in overnight for frac to close and gel to break, then flow or swab well back through properly staked lines to an open rig tank to clean up and evaluate treatment.

POLYEMULSION PROPPANT SCHEDULE

CABRE ET AL MELLOWDALE BASAL QUARTZ SANDSTONE

Slur per Stage m3	Cum Slur m3	Oil per Stage m3	Cum Oil m3	Water per Stage m3	Cum Water m3	Sand Conc kg/m3	Cum Sand tonne	Remarks
								Start cum. values
25.0	25.0	16.7	16.7	8.3	8.3			Pad volume
3.1	28.1	2.0	18.7	1.0	9.3	100	0.30	2040 mesh sand
3.2	31.3	2.0	20.7	1.0	10.3	200	0.90	2040 mesh sand
3.5	34.8	2.0	22.7	1.0	11.3	400	2.10	2040 mesh sand
3.7	38.5	2.0	24.7	1.0	12.3	600	3.90	2040 mesh sand
3.9	42.4	2.0	26.7	1.0	13.3	800	6.30	2040 mesh sand
8.3	50.7	4.0	30.7	2.0	15.3	1000	12.30	2040 mesh sand
9.4	60.0	4.3	34.9	2.1	17.5	1200	20.00	2040 mesh sand
		12.0						Oil flush
							20.00	tonne total proppant

Fluid Requirements

Crude Oil	Program above	34.9 m3(	220 bbl)
	Flush	12.0 m3(	76 bbl)
	Tank bottoms	6.1 m3(	38 bbl)
	Total	53.0 m3(	333 bbl)
	Requires 1 X 63.3 m3 tanks		
Water	Program above	17.5 m3(	110 bbl)
	Tank bottoms	6.5 m3(	41 bbl)
	Total	24.0 m3(	151 bbl)
	Requires 1 X 33.2 m3 tanks		

APPENDIX E

Summary of Coalbed Stimulation Treatments
Conducted from July 1970 to December 1979
(after Lambert et al., 1980b)

SUMMARY OF COALBED STIMULATION TREATMENTS CONDUCTED FROM JULY 1970 TO DECEMBER 1979

(after Lambert et al, 1980)

ID No.	Date Stimulated	Coalbed Name	Location County, State	Well No.	Depth to Coalbed (m)	Coalbed Thickness (m)	Type of Stimulation Treatment	Volume Treatment Fluid (m^3)	Frac Sand Mesh Size and Weight (kg)	Breakdown Gauge Pressure (MPa)	Treatment Gauge Pressure (MPa)	Injection Rate (m^3/min)	Production Pre Stimulation (m^3/d)	Production Post Stimulation (m^3/d)	Remarks
1	Jul.1970	Pocahontas No.1	Buchanan VA	Federal No.1	465	1.4	Gel	56	10 - 20 1800	22.1	24.1	1.7	20	340	Screen-out, flowback successful, treatment completed.
2	Jun.1973	Mary Lee	Jefferson AB	No.15W	328	1.5	Gel	38	10 - 20 2700	5.5	7.9	1.6	140	1420	
3	Nov.1973	Pittsburgh	Washington PA	No.1NE	131	1.2	Gel	39	10 - 20 2700	3.4	10.3	1.8	190	710	Screen-out, flowback successful, treatment completed
4	Feb.1974	Pittsburgh	Washington PA	No.25E	118	1.7	Gel	30	10 - 20 1800	5.5	10.1	1.7	60	510	Screen-out, flowback successful, treatment completed.
5	Feb.1974	Illinois No.6	Jefferson IL	No.1NE	223	2.7	Gel	46	10 - 20 2900	6.9	6.2	1.6	10	120	Intercepted by mining May 1974. Measured 416 ft of induced fracture.
6	Feb.1974	Pittsburgh	Washington PA	No.5C	161	1.7	Gel	51	10 - 20 2000	3.4	9.0	1.6	130	570	Screen-out, flowback successful, treatment completed.
7	Feb.1974	Pittsburgh	Washington PA	No.1SW	118	1.6	Gel	55	10 - 20 3600	3.4	8.9	1.5	10	480	Screen-out, flowback successful, treatment completed.
8	Mar.1974	Pocahontas No.1	Wyoming WV	No.2SE	223	1.2	Gel	50	10 - 20 2300	8.3	13.8	1.3	30	260	
9	Mar.1974	Hartshorne	Le Flore OK	No.5C	169	1.2	Gel	45	10 - 20 2300	5.5	8.3	2.0	30	230	Screenout, flowback successful, treatment completed.
10	Apr.1974	Pittsburgh	Washington PA	USBM No.4	179	1.8	Gel	28	10 - 20 1600	3.4	11.0	1.7	not produced	not produced	Intercepted by mining June 1974. Measured approximately 11 m of induced fracture.
11	Apr.1974	Castlegate Subseam No.3	Carbon UT	No.1SW	310	1.8	Gel	39	10 - 20 2700	8.3	17.9	1.3	0	30	
12	Jun.1974	Beckley	Fayette WV	No.203-A	300	1.5	Gel	54	10 - 20 2300	3.4	12.4	1.8	not produced	250	Screen-out, flowback successful, treatment completed.
13	Nov.1974	Beckley	Fayette WV	No.203-A	300	1.5	Gel	80	20 - 40 4500	15.2	17.2	1.7	250	250	Restimulation.
14	Nov.1974	Pittsburgh	Marion WV	No.1SW	256	1.7	Gel	57	20 - 40 2300	13.1	13.4	1.8	10	480	

SUMMARY OF COALBED STIMULATION TREATMENTS CONDUCTED FROM JULY 1970 TO DECEMBER 1979

(after Lambert et al, 1980)

ID No.	Date Stimulated	Coalbed Name	Location County, State	Well No.	Depth to Coalbed (m)	Coalbed Thickness (m)	Type of Stimulation Treatment	Volume Treatment Fluid (m^3)	Frac Sand Mesh Size and Weight (kg)	Breakdown Gauge Pressure (MPa)	Treatment Gauge Pressure (MPa)	Injection Rate (m^3/min)	Production: Pre Stimulation (m^3/d)	Production: Post Stimulation (m^3/d)	Remarks
15	Dec.1974	Pittsburgh	Marion WV	No.4NW	278	1.7	Gel	95	20 - 40 4500	9.7	14.5	1.7	200	760	
16	Jan.1975	Middle Kittanning	Allegheny PA	No.2	246	1.4	Gel	114	10 - 20 9100	16.5	10.3	2.1	not produced	40	Gel material produced with water. Completed through perforation.
17	Nov.1975	Beckley	Raleigh WV	No.LR-4	371	1.2	Gel	23	20 - 40 1800	17.9	15.9	1.4	Not produced	Not produced	Screen-out, treatment aborted.
18	Nov.1975	Beckley	Raleigh WV	No.LR-4	371	1.2	Gel	52	10 - 20 2000 20 - 40 1100	17.9	17.9	1.8	Not Produced	80	Restimulation.
19	Nov.1975	Mary Lee	Jefferson AL	No.TW-1	339	1.7	Gel	23	20 - 40 1100	12.3	8.0	1.7	Not produced	170	Intercepted by mining. No treatment, induced fracture found.
20	Jan.1976	Beckley	Raleigh WV	No.LR-3	364	1.5	Gel	54	20 - 40 4500	19.3	16.5	1.9	Not produced	60	
21	Apr.1976	Pittsburgh	Greene PA	No.EM-5	177	1.8	Foam	111	20 - 40 6400	6.6	10.3	2.3	Not produced	1930	Intercepted Nov. 1978. Measured 6 m of fracture. Screen-out treatment aborted.
22	Jun.1976	Pittsburgh	Greene PA	No.EM-1	194	1.8	Foam	125	20 - 40 5700	4.1	9.7	1.8	Not produced	310	Screen-out, flowback successful, treatment completed.
23	Jul.1976	Marmoth	Schuylkill PA	Parker No.2	622	3.0	Foam	55	20 - 40 3900	25.5	27.6	1.4	Not produced	Not available	Multiple-zone completion, production from single coalbed not determined.
24	Aug.1976	Pittsburgh	Green PA	No.EN-3	275	1.8	Foam	96	20 - 40 5000	55.2	11.0	1.8	Not produced	650	Screen-out, treatment aborted. Completed through performations.
25	Aug.1976	Pittsburgh	Green PA	No.EM-4	257	1.8	Foam	148	20 - 40 4500	6.6	9.0	1.7	Not produced	450	
26	Aug.1976	Holmes	Schuylkill PA	Parker No.2	569	3.7	Foam	53	20 - 40 3100	22.1	17.2	1.0	Not produced	Not available	Screen-out, treatment aborted. Completed through perforations.
27	Sep.1976	Pittsburgh	Green PA	No.EM-5	233	1.8	Foam	119	20 - 40 4500	5.5	9.7	1.8	Not produced	2830	Intercepted July 1978. Measured 45 m of induced fracture.

SUMMARY OF COALBED STIMULATION TREATMENTS CONDUCTED FROM JULY 1970 TO DECEMBER 1979

(after Lambert et al, 1980)

ID No.	Date Stimulated	Coalbed Name	Location County, State	Well No.	Depth to Coalbed (m)	Coalbed Thickness (m)	Type of Stimulation Treatment	Volume Treatment Fluid (m^3)	Frac Sand Mesh Size and Weight (kg)	Breakdown Gauge Pressure (MPa)	Treatment Gauge Pressure (MPa)	Injection Rate (m^3/min)	Production: Pre Stimulation (m^3/d)	Production: Post Stimulation (m^3/d)	Remarks
28	Sep.1976	Pittsburgh	Green PA	No.EM-7	222	1.8	Foam	110	20 - 40 3400	5.5	9.7	1.7	Not produced	2460	Intercepted Dec. 1978. Measured 24 m of induced fracture. Screen-out, treatment aborted.
29	Sep.1976	Beckley	Raleigh WV	No.LR-6	200	1.5	Foam	64	20 - 40 6800	4.1	10.3	1.9	Not produced	420	
30	Sep.1976	Pittsburgh	Green PA	No.EM-8	197	1.8	Foam	161	20 - 40 5800	5.5	7.6	1.7	Not produced	340	
31	Sep.1976	Holmes	Schuylkill PA	Parker No.2	569	3.7	Foam	38	20 - 40 2400	12.4	18.6	1.0	Not produced	Not available	Restimulation, multiple-zone completion. Production from single coalbed not determined.
32	Oct.1976	Primrose	Schuylkill PA	Parker No.2	535	3.4	Foam	38	20 - 40 2700	20.0	19.3	1.0	Not produced	Not available	Multiple-zone completion, production from single coalbed not determined.
33	Oct.1976	Mary Lee	Jefferson AB	No.TW-2	333	1.5	Gel	13	10 - 20 1400 20 - 40 500	not observed	17.9	1.3	Not produced	420	Screen-out, treatment aborted. Gel produced with water. Completed through perforations.
34	Oct.1976	Orchard	Schuylkill PA	Parker No.2	483	3.0	Foam	31	20 - 40 1400	22.1	19.3	1.0	Not produced	Not available	Multiple-zone completion, production from single coalbed not determined.
35	Nov.1976	Diamond	Schuylkill PA	Parker No.2	418	1.8	Foam	38	20 - 40 1400	29.6	19.3	1.0	Not produced	Not available	Multiple-zone completion, production from single coalbed not determined.
36	Nov.1976	Mary Lee	Jefferson AB	No.TW-3	327	1.5	Foam	78	20 - 40 6800	5.5	11.0	1.6	Not produced	1980	Intercepted by mining on Oct. 1977. Measured 85 m of induced fracture.
37	Nov.1976	Peach Mountain	Schuylkill PA	Parker No.2	246	2.1	Foam	36	20 - 40 1400	17.9	8.3	1.0	Not produced	Not available	Multiple-zone completion, production from single coalbed not determined.
38	Nov.1976	Tunnel	Schuylkill PA	Parker No.2	183	3.0	Foam	38	20 - 40 1400	17.2	13.1	1.0	Not produced	not available	Multiple-zone completion, production from single coalbed not determined.
39	May.1977	Pittsburgh	Schuylkill PA	No.CNG-1034	230	2.1	Foam	83	10 - 20 700 20 - 40 8600	5.5	8.3	1.6	3	70	Casing set in coalbed.
40	May.1977	Pittsburgh	Greene PA	No.EM-11	217	1.8	Keil*	207	20 - 40 4500	not observed	8.3	3.0	Not produced	1980	Intercepted by mining.

SUMMARY OF COALBED STIMULATION TREATMENTS CONDUCTED FROM JULY 1970 TO DECEMBER 1979

(after Lambert et al, 1980)

ID No.	Date Stimulated	Coalbed Name	Location County, State	Well No.	Depth to Coalbed (m)	Coalbed Thickness (m)	Type of Stimulation Treatment	Volume Treatment Fluid (m^3)	Frac Sand Mesh Size and Weight (kg)	Breakdown Gauge Pressure (MPa)	Treatment Gauge Pressure (MPa)	Injection Rate (m^3/min)	Production Pre Stimulation (m^3/d)	Production Post Stimulation (m^3/d)	Remarks
41	Jun.1977	Pittsburgh	Greene PA	No.CMG-1035	205	1.8	Foam	45	20 - 40 5400	3.4	8.3	1.6	10	130	Screen-out, treatment terminated.
42	Jul.1977	Mary Lee	Jefferson AB	No.TW-4	325	1.5	Foam	46	20 - 40 1100	4.8	9.7	1.6	Not produced	2830	Intercepted by mining on Nov.16, 1977. Measured 60 m of induced fracture.
43	Jul.1977	Mary Lee	Jefferson AB	No.22	334	1.8	Foam	186	20 - 40 18900	5.5	9.0	1.6	Not produced	570	
44	Jul.1977	Mary Lee	Jefferson AB	No.9	330	1.4	Gel-CO_2	213	20 - 40 7000	not observed	11.7	1.6	Not produced	280	Screen-out, treatment aborted. Gel produced with water. Completion through perforations.
45	Jul.1977	Mary Lee	Jefferson AB	No.TW-3	324	1.0	Foam	19	20 - 40 700	4.1	6.9	0.8	Not produced	not available	Multiple-zone completion, single coalbed production not determined. Upper bench stimulation. Completed through perforations.
46	Aug.1977	Mary Lee	Jefferson AB	No.7	327	1.4	Kiel*	302	20 - 40 11300	not observed	7.6	3.1	Not produced	6650	
47	Oct.1977	Mary Lee	Jefferson AB	No.6	343	1.4	Foam	175	20 - 40 16800	5.5	6.9	1.6	Not produced	2100	
48	Oct.1977	Mary Lee	Jefferson AB	No.4	309	1.6	Foam	191	20 - 40 20600	5.5	7.6	1.6	Not produced	3460	
49	Oct.1977	Mary Lee	Jefferson AB	No.8	326	1.2	Foam	191	20 - 40 20600	5.5	6.2	1.6	Not produced	3000	
50	Oct.1977	Mary Lee	Jefferson AB	No.5	308	1.6	Foam	191	20 - 40 20600	5.5	6.9	1.6	Not produced	1500	
51	Oct.1977	Mary Lee	Jefferson AB	No.13	325	1.5	Foam	191	20 - 40 20600	5.5	6.9	1.6	Not produced	2270	
52	October 1377	May Lee	Jefferson AB	No.14	327	1.6	Foam	143	20 - 40 9700	5.5	6.9	1.6	Not produced	3120	Treatment terminated, communication with adjacent well.
53	Oct.1977	Mary Lee	Jefferson AB	No.24	328	1.7	Foam	186	20 - 40 19700	6.2	7.6	1.6	Not produced	1300	

SUMMARY OF COALBED STIMULATION TREATMENTS CONDUCTED FROM JULY 1970 TO DECEMBER 1979

(after Lambert et al, 1980)

ID No.	Date Stimulated	Coalbed Name	Location County, State	Well No.	Depth to Coalbed (m)	Coalbed Thickness (m)	Type of Stimulation Treatment	Volume Treatment Fluid (m^3)	Frac Sand Mesh Size and Weight (kg)	Breakdown Gauge Pressure (MPa)	Treatment Gauge Pressure (MPa)	Injection Rate (m^3/min)	Production Pre Stimulation (m^3/d)	Production Post Stimulation (m^3/d)	Remarks
54	Oct.1977	Mary Lee	Jefferson AB	No.12	321	1.6	Foam	184	20 - 40 19600	5.5	8.3	1.6	Not produced	2660	
55	Nov.1977	Mary Lee	Jefferson AB	No.25	321	1.6	Foam	184	20 - 40 19700	5.5	7.6	1.6	Not produced	2210	
56	Nov.1977	Mary Lee	Jefferson AB	No.15	331	1.7	Foam	191	20 - 40 20800	5.5	7.6	1.6	Not produced	2010	
57	Nov.1977	Mary Lee	Jefferson AB	No.23	334	1.5	Foam	194	20 - 40 20500	6.2	9.0	1.6	Not produced	2830	
58	Nov.1977	Mary Lee	Jefferson AB	No.18	312	1.3	Foam	209	20 - 40 19700	6.2	11.0	1.6	Not produced	1050	
59	Nov.1977	Mary Lee	Jefferson AB	No.3	335	1.5	Foam	178	20 - 40 18200	5.5	7.6	1.6	Not produced	4870	
60	Nov.1977	Mary Lee	Jefferson AB	No.16	319	1.7	Foam	143	20 - 40 10100	5.5	8.6	1.6	Not produced	2610	Treatment terminated. Communication with adjacent well.
61	Jul.1978	Jawbone	Dickenson VA	No.DC-1A	130	1.5	Foam	134	20 - 40 12700	6.9	7.6	2.5	Not produced	850	
62	Oct.1978	Seven Coalbeds	Westmoreland PA	WEC FEE No.4	149-200	2.2	Kiel*	358	20 - 40 11800	not observed	20.7 avg.	4.1	Not produced		Two zones treated through perforations.
63	Oct.1977	Five Coalbeds	Westmoreland PA	WEC FEE No.4	59-137	5.9	Kiel*	672	20 - 40 22700	not observed	8.3	4.8	Not produced		
64	Dec.1978	Mary Lee	Jefferson AB	No.TW-5	349	1.7	Foam	201	0	6.9	11.0	0.7	Not produced	1270	Intercepted by mining July 12, 1979. Underground study in progress.
65	May.1979	Pittsburgh	Greene PA	EM-20	213	1.5	Foam	75	20 - 40 11600	41.4	9.2	1.6	Not produced		
66	Aug.1979	Jawbone	Dickenson VA	No.DC-3B	135	1.8	Foam	111	20 - 40 7100	5.5	5.5	1.9	Not produced		
67	Sep.1979	Jawbone	Dickenson VA	No.DC-4	131	1.5	Foam	111	20 - 40 7200	6.2	6.9	1.6	Not produced		

SUMMARY OF COALBED STIMULATION TREATMENTS CONDUCTED FROM JULY 1978 TO DECEMBER 1979

(after Lambert et al, 1980)

ID No.	Date Stimulated	Coalbed Name	Location County, State	Well No.	Depth to Coalbed (m)	Coalbed Thickness (m)	Type of Stimulation Treatment	Volume Treatment Fluid (m^3)	Frac Sand Mesh Size and Weight (kg)	Breakdown Gauge Pressure (MPa)	Treatment Gauge Pressure (MPa)	Injection Rate (m^3/min)	Production Pre Stimulation (m^3/d)	Production Post Stimulation (m^3/d)	Remarks
68	Oct.1979	Pocahontas No.3	Buchanan VA	VV-N No.90	565	1.8	Foam	15	20 - 40 900	Not observed	15.9	0.6	Not produced	570	Small volume treatment due to close proximity to mining.
69	Dec.1979	Pocahontas No.3	Buchanan VA	VV-N No.91	672	2.1	Foam	17	20 - 40 700	6.9	16.5	0.6	113	new well	Communication around packer; treatment aborted.
70	Dec.1979	Jawbone	Dickenson VA	No.DC-2C	206	1.5	Foam	100	0	6.2	8.9	1.3	Not produced		
71	Dec.1979	Jawbone	Dickenson VA	No.DC-5D	205	1.5	Foam	92	20 - 40 6400	4.8	6.9	1.6	Not produced		